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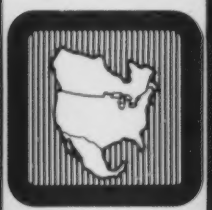
Reliability Assessment 1991-2000

The Future of Bulk Electric System Reliability in North America



North American Electric Reliability Council

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The Future of
Bulk Electric System Reliability
in
North America

North American Electric Reliability Council

September 1991

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Foreword

About NERC

The North American Electric Reliability Council (NERC) was formed in 1968 by electric utilities to coordinate, promote, and communicate about the RELIABILITY of their generation and transmission systems. It is comprised of nine Regional Reliability Councils and one Affiliate that together encompass virtually all of the electric utility systems in the United States, Canada, and the northern portion of Baja California, Mexico.

The activities of NERC are directed by its Board of Trustees. This Board is comprised of some 30 electric utility executives that include the Board's officers, two representatives from each Regional Council, and others as needed to assure at least one representative from a Canadian utility and at least two from each type of utility ownership segment.

Meetings of the Board are attended by observers from the U.S. Department of Energy, the Federal Energy Regulatory Commission, the National Energy Board of Canada, and several electric utility industry associations — the Edison Electric Institute, American Public Power Association, National Rural Electric Cooperative Association, Electric Power Research Institute, Canadian Electrical Association, and the National Association of Regulatory Utility Commissioners.

The technical activities of NERC are conducted by its Engineering and Operating Committees and their subgroups that together total over 200 utility representatives. NERC's strength lies in its ability to call on these and other electric utility managerial and technical experts from the Regions to address planning, engineering, and operating reliability issues.

NERC's staff, located in Princeton, New Jersey, works with the Board, the Regional Councils, and the NERC Committees and their subgroups to provide project coordination and support. Each Regional Council also has its own staff.

About This Report

The NERC Board of Trustees created the Reliability Assessment Subcommittee (RAS) in 1970 to annually review the overall reliability of the existing and planned generation and transmission systems of the nine Regional Reliability Councils.

This *Reliability Assessment 1991-2000* report presents:

- An assessment of electric generation and transmission reliability through 2000,
- A discussion of the key issues affecting the reliability of future electric supply, and
- Detailed Regional assessments of electric supply reliability, including reliability issues of specific Regional concern.

This report reflects the expertise, judgment, and interpretations of the RAS members. In preparing this report, the RAS interviewed representatives of selected Regions and reviewed summaries of Regional self-assessments, including aggregate forecasts of peak demand and planned resources. The RAS appraised Regional plans for future electric generation and transmission facilities, and assessed the potential effect of legislation, regulations, and governmental policies on future electric supply reliability. A reliability assessment of the interconnected Railbelt electric systems of the Alaska Systems Coordinating Council (ASCC), the NERC Affiliate, is also included.

Unless otherwise noted, the data reflects conditions as of January 1, 1991. Detailed background data, which is the basis for this assessment report, is included in a companion July 1991 NERC report — *Electricity Supply & Demand 1991-2000*.

A summary version of this report as well as its companion data report are available from the NERC office.

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Executive Summary

Electric utilities expect to have adequate capacity resources through the year 2000. However, some are still developing plans for the additional resources that may be required. Ten-year plans are less specific than in the past because utilities are relying more on short lead-time resource options.

The transmission systems as planned will be adequate over the next ten years. However, delays in building new lines and increasing demands for transmission services are serious concerns.

Reliability is the fulcrum upon which economics and environmental impact should be balanced in a rational and timely review process. Utilities must be allowed to complete planned generation and transmission as scheduled. A reliable supply of electricity also depends on utilities and non-utilities adhering to established operating criteria.

Several key issues could prevent meeting reliability goals:

Clean Air Regulations — Utilities face near-term reliability challenges from the potential effects of complying with clean air regulations in the United States and Canada. Preliminary compliance strategies focus on switching to lower sulfur coal and adding scrubbers. Uncertainties about mining and transportation, and the timely availability of equipment and skilled labor are concerns.

Fuel Supply Adequacy — Natural gas use for electricity generation is expected to increase significantly. This increase is of particular concern to utilities that have not been major users of natural gas. The curtailment of fuel to utility or non-utility gas-fired capacity during winter could pose problems. Another concern is the ability of gas suppliers to deliver fuel reliably to the increasing number of peaking combustion turbines with their sudden startup and operation for only a few hours a day.

Operating Complexities — Reliable operation of the interconnected electric systems is becoming more complex. Clean air regulations will complicate economic generation dispatch and could limit the availability of emergency generation assistance. Increasing demands for transmission services, the proliferation of non-utility generators, and increased line loadings will add to the complexities.

Transmission Siting and Services — Increasing obstacles to siting and certification of needed transmission lines make expansion of transmission extremely difficult. Concern about alleged adverse health effects due to electric and magnetic fields is a major issue in the approvals process that can cause delay or cancellation of transmission facilities. Increasing demands for transmission services, including legislative proposals for mandated services, could jeopardize reliability.

Changing Business Environment — The changing business environment poses several challenges to electric utilities. Increasing use of non-utility generators and demand-side management means electric utilities will have less direct control over the resources needed to maintain reliability. Mandatory inclusion of "environmental externalities" and "societal costs" in the evaluation of resource alternatives will further cloud the planning process. Also, regulatory impediments continue to be disincentives to maintaining reliability, but some encouraging signs exist.

The "Regional Reliability Assessments" section of the report also identifies a number of concerns to maintaining electric system reliability. These Regional-specific reliability issues include:

ECAR — An increase in peak demand growth, a decline in generation availability, or the impacts of compliance with clean air legislation could reduce reliability to inadequate levels. Portions of the transmission network will continue to be operated at times near transfer capability limits requiring the use of effective operating procedures to maintain reliability.

ERCOT — Delays in needed transmission lines and natural gas supply disruptions are major concerns. The ability of current fuel oil inventories to maintain electric system reliability for an extended period of natural gas curtailment is also a concern.

MAAC — Significant amounts of non-utility generation and demand-side management have been included in the projected resources. If peak demand grows faster than projected, or non-utility generator additions or projections of demand-side management do not materialize, MAAC may be faced with the need to add increased amounts of short lead-time generating capacity.

MAIN — This Region plans to provide adequate generating capacity on a continuing basis. Probability studies show that when demand forecast uncertainty is considered, MAIN may have to provide additional resources as early as 1994. Consequently, MAIN is already investigating the effectiveness of various strategies to assure adequate reliability.

MAPP — A near-term reliability concern is the drought condition in this Region. In the longer-term, a higher than projected peak demand could cause some reliability concerns near the end of the assessment period.

NPCC — Significant amounts of non-utility generation and demand-side management have been included in the projected resources, especially in New York, New England, and Ontario. Concerns regarding the dependability of these options on a long-term basis and their availability during peak demand periods increase the uncertainties in resource planning in these areas.

SERC — The main reliability concern is the large number of modifications required on coal-fired generating plants in a short time frame to comply with clean air legislation. This activity could cause reduced availability of generating units during that period.

SPP — Reliability concerns include the effect of regulations associated with clean air legislation, the deliverability of natural gas, and the impact of increasing demands for transmission services.

WSCC — The Region's reliability challenges include fuel supply adequacy, effects of electric and magnetic fields, environmental concerns, use of special protection systems, and demand forecast uncertainty. WSCC believes that these concerns can be responsibly managed to avoid degradation of electric system reliability.

Why reliability? Electricity is a necessity of modern life. The highly reliable electricity supply enjoyed by the citizens of the United States and Canada is no accident. It is possible only because of the vigilant pursuit of reliability in planning, constructing, maintaining, and operating the electric systems. This practice must continue.

Why Reliability?

Electricity is a necessity of modern life. All sectors of society —residential, commercial, and industrial — have become increasingly dependent upon electricity. The business segment, in particular, relies on electricity to keep its highly computerized infrastructure of machines and equipment operational. No substitute is available for electricity in many of its applications.

Citizens of the United States and Canada enjoy a highly reliable supply of electricity. This reliability was not achieved by accident. It was achieved only by the vigilant pursuit of reliability in planning, constructing, maintaining, and operating the electric systems. However, forces exist that tend to impede or discourage such pursuits. These forces must be effectively managed by both electric utilities and policymakers to ensure that reliability does not deteriorate with resulting adverse effects on lifestyles and society's standard of living.

How has Reliability Been Achieved?

Society's reliance on electricity and the highly reliable systems that fostered this reliance did not happen overnight. Both were developed as a result of the evolution and growth of electric utilities.

Reliability is attained by planning electric systems to be reliable, building the systems in accordance with those plans, properly maintaining facilities, and operating the systems to ensure a reliable supply of electricity to all. Increased knowledge, interconnected operation, and sophisticated equipment used by utilities have reduced customer interruptions and have continued to reinforce customer expectations and confidence.

Electric utilities have evolved from town "light plants" supplying lighting for streets and buildings in the cities and from rural "windchargers" on individual farms, to electric companies and rural cooperatives supplying increasingly larger areas, and finally to the interconnected electric systems of today. As electricity became more generally available, increasingly affordable, and more dependable, people relied more and more on electricity to take the drudgery out of their existence, improve their productivity, and do their work for them. As people depended more on electricity and expected it to be ever present, the reliability of its supply also became more important.

One of the main actions taken by electric utilities that both reduced costs and enhanced reliability was the building of transmission lines that connected with neighboring utilities to provide sharing of generation. This sharing reduced the number of required generation facilities, and lowered the cost to the customer while improving the reliability of electric supply. Over the years, additional interconnecting lines and an overlay of higher and higher voltage transmission lines were constructed.

Today's electrically interconnected network is one of the most complex machines ever built. But — for such a complex machine to function properly and reliably, it must be operated with a great degree of skill, dedication, and coordination. The interconnected systems of the nine Regions of the North American Electric Reliability Council (NERC) provide a very high level of service reliability to their customers. Customers count on it — in fact, they can't get along without it!

How is Reliability Sustained?

Perhaps the most notable feature of this complex machine is that it is made up of hundreds of individual electric systems serving their own local customers while at the same time contributing to the overall interconnected network. This contribution to the network can only occur with extensive coordination — coordination of operations of individual systems on a day-to-day, even minute-to-minute, basis; coordination of automatic devices built into the systems; coordination of standards for designing and constructing the systems; and coordination in the

planning of system expansion. This coordination is realized through agreements among utilities, power pools, and the Regional Reliability Councils, and through NERC. Through these agreements, groups of experts in the planning, engineering, and operating disciplines address the many aspects of interconnected system reliability.

Consequences of Supply Interruptions

Widespread electric supply interruptions can have drastic impacts on our safety, our economy, and our lifestyle. These impacts and consequences include:

- Disruption of home and business activities,
- Extensive economic losses,
- Life threatening conditions,
- Severe limitations in lifestyle,
- Physical damage to equipment and facilities, and
- Looting and vandalism.

Widespread electric supply disruptions can bring electrified, computer-dependent, highly-automated societies to an abrupt halt. The more advanced society becomes, the greater become the benefits of reliable electric service, and the more adverse the societal and economic effects of unreliable service. Fortunately, in the United States and Canada such interruptions have been infrequent.

Loss of electric supply resulting in widespread disruptions can be caused by either malfunctions in the transmission systems that carry electricity from the generating source to the areas of customer need or by insufficient generating capacity. In the NERC areas, the relatively few significant blackouts have resulted from loss of transmission, either from severe natural causes or from loading portions of the transmission systems beyond the limits of their capability. Restoration of electrical service to customers can require hours to days. However, restoration of the transmission systems to their full capability can take from days to several months depending on the cause of loss and the extent of equipment damage.

The more serious and potentially longer lasting cause of interruption is one arising from insufficient generating capacity to meet customer needs. This situation was demonstrated in Argentina in 1989 due to long-term generating capacity deficiencies. The capital city of Buenos Aires experienced chronic electricity shortages on a daily basis that limited working hours, lighting, subway operation, operation of elevators in tall buildings, and television broadcasts.

More recently in Japan, the major utilities, in response to criticism for having excess generating capacity, permitted their capacity margins to decline. In 1990, Tokyo just made it through the summer with the help of some 400 industries agreeing to accept electricity cutoffs with as little as three hours notice. These utilities will need about five years to build enough power plants to reestablish an adequate capacity margin.

If electric supply inadequacies and the frequency of interruptions experienced in either of those countries were to occur in any NERC Region, the ramifications would be enormous. Reliable supply is not only essential to individual customers and businesses, it is crucial to the economic health of entire regions.

Limits to Reliability

A 100% reliable supply of electricity cannot be achieved even if cost were no object. Disruptions to electrical supply can and do occur. The public has tolerated service interruptions where these interruptions were few in number and service restoration was relatively quick. On the other hand, public reaction to prolonged interruptions can be strong, particularly when the source of the disturbance is not readily attributable to severe natural causes, such as hurricanes, tornadoes, earthquakes, or the more common ice storms.

What is the Future of Reliability?

Reliability is not achieved by accident. It can only be achieved and sustained by planning, building, maintaining, and operating the systems with reliability as the paramount objective. This is easier said than done.

A number of forces exist that impede or discourage electrical supply developments. These forces include constraints imposed by legislative and regulatory actions, environmental restrictions, and risks associated with financing the necessary facilities.

The future of reliable operation in an increasingly competitive business environment depends on electric utilities, regulators, and government working in concert to manage the challenges to reliability. All concerned must consider reliability as well as economics and environmental constraints.

To ensure a reliable supply of electricity in the future, it is necessary to plan for that future. This report assesses the reliability of the electric supply plans for the next ten years and identifies the issues that could affect reliability. Hopefully, the report will also help focus electric utilities and policymakers in their efforts toward maintaining a reliable supply of electricity.

Clean Air Regulations

The U.S. Environmental Protection Agency is still developing the rules and regulations needed to implement the U.S. Clean Air Act Amendments of 1990 (CAAA). Therefore, electric utilities cannot now determine the final, precise impact of the CAAA on their generating capability.

Preliminary estimates indicate that compliance with CAAA Phase I SO_2 requirements, involving 78,600 MW of existing U.S. coal-fired generating capacity, may be achieved by: fuel switching (63%) primarily to lower sulfur coals, the installation of scrubbers (25%), the use of allowances (11%), and other (1%).

Concerns about Phase I compliance include: the capability of Eastern mines to provide substantial additional quantities of low sulfur coal, the timely availability and installation of equipment required for fuel switching and for scrubbers, and the availability of rail cars and the ability of railroads to transport an estimated additional 50 million tons/year of low sulfur Western coal to the east.

In Canada, utilities are coping with existing clean air regulations with increased costs but minimal reliability problems. However, more stringent proposed regulations could have serious reliability implications. Concerns include: the ability to implement emissions controls and resource replacements on schedule, the increased use of natural gas, and the increased loadings on the transmission network due to environmental dispatch.

Recent Legislation

Electric utilities recognize the need for environmental protection and continue to implement measures to minimize the effects of construction and operation of electrical facilities on the environment. However, increased environmental concerns as well as changes to environmental regulations have the potential to adversely affect electric system reliability and cost.

On November 15, 1990, the U.S. Clean Air Act Amendments (CAAA) became law. Basically, the CAAA seeks to reduce sulfur dioxide (SO_2) emissions from electric utility power plants to about 50% of 1980 levels, and places a cap of 8.95 million tons/year (mmtpy) on SO_2 emissions beginning in the year 2000. The U.S. Environmental Protection Agency (EPA) is still drafting the details of the new regulations required to implement the CAAA, and utilities are still developing their responses to this new legislation and pending regulations.

Existing clean air regulations in eastern Canada already require a 50% reduction in SO_2 emissions from 1980 levels by 1994 with a total Canadian emissions cap of 3.5 mmtpy by the year 2000. Ontario Hydro, Canada's largest fossil-fired electric utility, is significantly affected. In addition, more stringent regulations have been proposed by both the federal and Ontario governments.

Utilities have serious concerns about the effects that compliance with the CAAA and the proposed Canadian regulations could have on electric system reliability. Although these concerns may appear to be surmountable from an individual electric utility point of view, when viewed on an overall basis, they represent major challenges to maintaining reliability.

U.S. Clean Air Act Amendments of 1990

Possible Utility Actions — Several ways to meet the SO_2 emission limitations of the CAAA are available. They include: changing the fuel burned in affected units — switching to lower sulfur coal, lower sulfur oil, or natural

gas; removing SO_2 after combustion by adding scrubbing equipment, or possibly removing sulfur using clean coal technologies; the accumulation, purchase, or selling of SO_2 allowances; reducing the generation of units with high emission rates; and unit retirement if the compliance costs exceed the unit's value.

To reduce emissions of nitrogen oxides (NO_x) by 1995, the utilities will probably respond by adding low NO_x burners because changing fuels may not provide a sufficient reduction.

Based on a recent NERC survey, an estimate of the preliminary responses of the affected electric utilities to Phase I of the CAAA is summarized in Table 1. Several of these compliance options and associated reliability concerns are addressed below.

Fuel Switching-Coal — Many utilities are considering converting high sulfur coal-fired generating units to lower sulfur coal. Several recent EPRI analyses have examined many factors affecting utility choices of coal supply under the CAAA. These references include EPRI IE-7110, "Utility Coal Markets Under Acid Rain Legislation" and the "EPRI Report Series on Low-Sulfur Coal Supplies," IE-7115 - 7118.

Over half of the capacity affected by Phase I of the CAAA may be switched to lower sulfur coal. Three major sources of low sulfur coal include: Eastern, Western high heat content, and Western low heat content.

- **Eastern Coal** — The Central Appalachia area is the major source of low sulfur Eastern coal used by electric utilities. This coal is attractive as it has a relatively high heat content, about 12,500 British thermal units per pound (Btu/lb), and other characteristics similar to the high sulfur coals now being burned in many power plants. A major reliability concern is the availability of the increased amount of this coal required to meet the potential utility needs shown in Table 1.

In 1989, the Central Appalachia area produced a total of 257 million tons of coal that could meet the new CAAA Phase I requirement of 2.5 pounds of SO_2 per million British thermal unit (lbs/mmBtu) of fuel input. Of this total production, 144 million tons were for domestic electric utilities. About 42 million tons of this domestic utility coal could also meet the new CAAA Phase II requirement of 1.2 lbs of SO_2/mmBtu of fuel input.

U.S. Clean Air Act Amendments of 1990

The U.S. Clean Air Act Amendments of 1990 (CAAA) reduce annual allowable electric utility sulfur dioxide (SO_2) emissions to 8.95 million tons beginning in the year 2000, slightly more than half of the 17.4 million tons of SO_2 emitted by utility power plants in 1980. Utility nitrogen oxides (NO_x) emissions are to be reduced by the year 2000 to about 2 million tons below levels existing in 1980.

Phase I

Phase I begins January 1, 1995. Major sources emitting at a rate above 2.5 pounds of SO_2 per million British thermal unit (lbs/mmBtu) of fuel input will be granted allowances in an amount equal to 2.5 lbs/mmBtu multiplied by their average 1985-87 Btu fuel input to each unit. About 110 utility generating plants, a total of 261 units, will be affected. Most of these units will be required to reduce NO_x emissions as well by the year 1995.

Phase II

Starting January 1, 2000, all major electric utility power plants will be granted allowances to limit annual SO_2 emissions to an amount equal to or slightly less than 1.2 lbs/mmBtu of fuel input multiplied by their average 1985-87 Btu fuel input to each unit to meet the annual 8.95 million ton cap. Also, these plants will need to meet new, but not yet defined, standards for NO_x emissions.

SO_2 Emission Allowances

Each source of SO_2 must obtain allowances to equal its emissions or face severe penalties. An allowance is a marketable federal authorization to emit one ton of SO_2 during or after a specified calendar year. For example, a typical unscrubbed 600 MW unit emitting 2.5 lbs of SO_2/mmBtu would require allowances equal to about 50,000 tons of SO_2/year.

If emissions from a source are reduced so that it needs fewer allowances than it has been granted, the excess allowances can be used at another plant in the same utility, held for future use, or sold to other sources.

Preliminary Electric Utility Responses[a] to the U.S. CAAA of 1990 — Phase I

	Capacity Affected	
	Thousands of MW	% Total
Fuel Switching		
Low Sulfur Eastern Coal	29.2[b]	37.1
Low Sulfur Western Coal	14.7[b]	18.7
Low Sulfur Local Coal	1.9	2.5
Natural Gas	2.4	3.1
Other	1.5	1.9
Subtotal	49.7	63.3
Scrubber (FGD System) Additions	19.5	24.7
Emission Allowances	8.4	10.7
Unit Retirements	0.3	0.4
Unknown	0.7	0.9
Total	78.6	100

[a]As of June 1991.
[b]Corresponds to additional coal production requirements of about 70 million tons/year for low sulfur Eastern coal and about 50 million tons/year for low sulfur Western coal, based on a 65% capacity factor.

Table 1

As a worst case scenario, the estimated conversions to low sulfur Eastern coal shown in Table 1 would require about 70 mmtpy based on a 65% capacity factor with all electrical energy provided by the low sulfur coal. If all of this compliance coal were to be CAAA Phase I coal from Central Appalachia, production for utilities would have to increase by 50% by 1995. If the increase were to be all in CAAA Phase II compliance coal, coal production for utilities would have to increase from 42 million to 112 million tons — a 167% increase. Thus, in either case, or in any combination of the two, the increased demand for low sulfur Appalachian coal by domestic utilities would be substantial. While some of this coal might be provided by a shift from non-utility uses, a large increase in mining capability would likely be needed. As two-thirds of Central Appalachia coal comes from deep mines, such a large increase in production would require a substantial investment in mining capability. In addition, there are transportation concerns such as the capacity of barge loading facilities and the lockage capacity on the Ohio River.

Several factors could make this low sulfur Eastern coal scenario less severe. For example, fuel blending, that is, mixing lower sulfur content coal (or possibly fuel oil or natural gas) with the higher sulfur content coal currently being burned, could reduce the potential tonnage of low sulfur Eastern coal required, as would fewer hours of unit generation per year. Also, if increased demand for low sulfur Eastern coal caused the price of this type of coal to soar, utilities would likely resort to other options such as scrubbers, which would reduce demand for this coal. Again, it must be emphasized that the Table 1 data is preliminary, and utility plans will change to minimize costs.

The reliability concerns with low sulfur Eastern coal relate to the timely availability of this coal, the timing of fuel switching changes and their effect on unit outage scheduling, and coal transportation problems.

- **Western High Heat Content Coal** — High heat content, low sulfur coal is available in some basins in Wyoming, Colorado, and Utah. Expansion of deep mining capability and transportation to the more distant coal markets, both likely to be very costly, could preclude widespread increased use of this coal.

- **Western Low Heat Content Coal** — Sub-bituminous, low heat content, low sulfur coal from the Powder River basin in Wyoming and Montana is abundant. Because it is surface mined, cost is relatively low and output could easily be expanded. In 1990, about 160 million tons of this coal were mined, which is about half the present design capacity of the mines. Based on Table 1, Phase I conversions to low sulfur Western coal could total about 50 mmtpy, so mining capability is expected to be adequate.

Transportation will be a key element in using low heat content, low sulfur Western coal. Fabrication of rail cars in time to meet the need, and the ability of the railroads to upgrade their lines to accommodate the increased traffic are reliability concerns. For example, about 11 coal trains per day carrying 12,000 tons each from Montana and Wyoming to the east would be needed to supply the 14,700 MW of conversions shown in Table 1. With a typical five-day-turnaround time, 55 addi-

tional trains would be required, a total of about 6,300 railroad cars. Preliminary indications are that both major rail carriers from the Powder River Basin in Wyoming and Montana are gearing up to expand their rail systems to deliver low sulfur coal to the new electric utility markets in the east.

Many generating plants will require hardware modifications, which could require several months of outage time, to avoid derating for a change in fuel to low sulfur Western coal. The typical heat content of Powder River basin coal is 8,500 Btu/lb, about 70% that of the high sulfur coal now being burned in many power plants. To avoid unit derating, more of this low heat content Western coal must be supplied to the boiler, or it must be blended with higher heat content coals or fuels such as oil or gas.

Low sulfur Western coals have characteristics that could cause problems in boiler slagging, in ash handling, and in the performance of existing electrostatic precipitators. The capacity of coal handling systems will generally need to be increased, and increased grinding capacity may be required. Further, the coal tends to be more of an explosion hazard. Yet, despite these problems, low sulfur Western coal is expected to play a major part in utility plans to meet CAAA requirements.

Scrubber Additions — As with other compliance options, scrubbers have some associated reliability concerns. One concern is the space available for retrofitting scrubbers to older generating units. If space is not available to add spare or backup scrubbing equipment, unit availability may be reduced when scrubber maintenance is required. Another problem is the disposal of waste from the scrubbing process.

A flue gas desulfurization (FGD) system or scrubber is, in effect, a chemical factory added to a generating unit to treat the flue gas from the boiler before it is emitted from the power plant stacks. Lime or limestone is usually used to remove or "scrub" the SO_2 from the exhaust gases. In Phase II, scrubbing is expected to play a major role in SO_2 reductions.

A recent NERC analysis, *Impact of FGD Systems*, over the 1986-1988 period shows that the net plant output of units equipped with scrubbers will be reduced by 1 to 2% due to the power requirements of the scrubbing equipment. Based on the 19,500 MW estimated in Table 1, total capacity output could be reduced by 200 to 400 MW. This same study showed that the effect of scrubbers was to increase a unit's equivalent forced outage rate by 0.45 percentage points on average.

Scheduling of Modification Outages — With fuel switching and scrubber additions expected to account for about 88% of the capacity in utility Phase I compliance planning, the scheduling of outages for power plant modifications will be critical. The early dates for compliance and limitations in design engineering manpower and manufacturing capability may cause problems in the timely delivery of materials necessary for adding scrubbers, new burners, and modifying coal handling systems. Although manufacturers are increasing their plant capacity to meet anticipated utility needs, they will be faced with a number of orders all with about the same delivery time (i.e., in time to get the facilities installed before 1995-1997).

With cutbacks in utility power plant construction in recent years, the highly specialized labor (e.g., boilermakers) to make the needed plant modifications could be in short supply. Unless this need is anticipated well in advance, the necessary training and apprenticeship programs will be unable to produce the skilled workers.

If power plant outages cannot be optimally scheduled, a greater overlapping of unit outages than originally expected will result. The net capacity reduction due to this modification work in a system and in neighboring systems could increase significantly and adversely impact reliability.

Use of SO_2 Emission Allowances — An important consideration in complying with the CAAA is the use, purchase, accumulation, or sale of SO_2 emission allowances. The allowance program will provide needed flexibility in scheduling generation. However, the program may have several possible adverse impacts on reliability depending on how the allowance market develops.

Allowances will likely impact inter-utility emergency generation assistance. For example, a utility faced with a need for allowances to have adequate capacity to serve its own customer demands would logically be very reluctant to use critical allowances to help another utility. Even if the utility is willing to provide assistance, allowance supply and cost will have to be negotiated before transactions can take place. These negotiations will add to operating complexities.

Utilities with large coal units in compliance or large nuclear units,

which may be a substantial portion of the utility's capability, are particularly concerned about their ability to cover outages of these units. If the utility did not have sufficient allowances and if none were available for purchase, generating capability would be reduced and reliability would suffer accordingly. Closing the books on emissions on December 31, in the middle of the winter peak demand period, would likely be troublesome. However, the adoption by EPA of a "truing-up" or "netting-out" period in the early months of the following year will help to reduce this concern.

Higher than expected use of coal-fired units during the year due to higher than projected customer demands, improved unit availability or performance, drought, or outages of other units may require additional allowances to continue operation of coal-fired units until year end. If the utility did not have these allowances and could not purchase them, reliability could be adversely affected.

Allowance availability will affect the operation and dispatch of utility generating units, which, in turn, will have some impact on the transmission systems. For example, if due to a shortage of allowances, a utility were to generate with more combustion turbines located closer to customer demand, the burden on the transmission system might be decreased. Purchases from neighbors could increase or decrease transmission system loadings depending on the direction of prior power flows.

Electricity transactions with Canada may be affected depending on the cost and availability of allowances in the United States, and the relative electrical energy production as determined by the SO_2 caps in Canada and the United States.

Early Retirement of Generators — Although preliminary estimates from Table 1 show anticipated Phase I retirements of only 300 MW, additional retirements may result in Phase II, depending on EPA's final determinations for NO_x controls.

Cost Impact on Reliability — Compliance with the CAAA will require significant capital expenditures for conversion of power plant boilers to alternate fuels and for scrubbers. Operating costs may also increase because the output of the most economical units may be limited or become more costly due to emissions constraints and increased fuel costs. Purchase of allowances also may prove to be expensive. For example, if the purchase price for an allowance were $1,000, then to operate entirely on allowances, the electricity cost for a 600 MW unit would increase by $12.50/megawatthour, or 1.25¢/kilowatthour. Further, regulatory treatment of both the capital costs for compliance and the allowance transactions is uncertain. With constraints on expenditures, some utilities may be forced to limit expenditures for generating capacity, demand-side management programs, and transmission projects. The result could be a reduction in reliability.

Canadian Clean Air Programs

Existing Acid Gas Emissions Programs — In 1985, the federal and provincial governments agreed to a program to cut SO_2 emissions to half of 1980 levels from all sources in Manitoba and provinces to the east by 1994, and to cap them at this new level of 2.5 million tons of SO_2/year thereafter. In 1991, the Western provinces were placed under an emissions cap of about 1 million tons of SO_2/year from all sources by the year 2000, for an annual total Canadian cap of about 3.5 million tons. Ontario Hydro is the largest Canadian electric utility emitter. Other Canadian utilities are either much smaller or use mostly hydro generation. This discussion, therefore, focuses primarily on Ontario Hydro with related comments on the New Brunswick Electric Power Commission and Nova Scotia Power Corporation.

The limits on electric utilities are in the form of a system cap on total annual emissions, regardless of the amount of electricity generation. Ontario Hydro is required to reduce in steps to no more than 193,000 tons/year of SO_2 and to no more than 237,000 tons/year of SO_2 plus NO_x by 1994. New Brunswick Electric Power is required to reduce its emissions of SO_2 to less than 143,000 tons/year by 1994, and Nova Scotia Power is required to stay below 176,000 tons/year.

- **Utility Actions** — The utility responses in Canada are similar to those for the United States. In fact, the Canadian utilities are already experiencing some of the problems that U.S. utilities are anticipating.

  Canadian utilities with hydro and nuclear generating capacity are maximizing electricity generation from those sources and limiting fossil fuels to a peaking role. In addition, just as in the United States, demand-side management, non-utility generators, and purchases from neighboring systems are also used to reduce a utility's reliance on fossil fuels where economic.

In Canadian provinces where coal is burned for electricity and other purposes, emissions are being reduced through use of either local or imported low sulfur coals (0.5 to 1.3 lbs SO_2/mmBtu). Natural gas or low sulfur oil are also sometimes substituted for coal to reduce emissions. Ontario Hydro has steadily lowered the sulfur content of its coal, thereby reducing emissions from about 3.8 lbs SO_2/mmBtu in the late 1970s to about 1.4 lbs SO_2/mmBtu at present.

Low NO_x burners, flue gas conditioners, and flue gas scrubbers will continue to be used in electric utility acid gas control programs. New Brunswick Electric Power and Ontario Hydro will be retrofitting several units with scrubbers starting in 1993 and 1994, respectively.

New clean coal technologies, which permit increased fossil-fired electricity generation with high levels of emissions controls, are included in electric utility long-range plans with some fluidized bed units already in the demonstration stage in Nova Scotia Power Corporation.

- **Reliability Concerns** — The reliability implications include capacity losses and reduced unit availability due to the addition of scrubbers, limits on the total amount of electricity produced from exiting fossil units, and possible retirement of some older, smaller coal-fired units. For example, flue gas conditioning, fitted by Ontario Hydro on twelve 500 MW units to permit the burning of lower sulfur coal and to reduce opacity, initially resulted in a loss of about 25 MW per unit.

  Environmental dispatch has also caused utilities to reschedule their generating units and make electricity purchases to meet emissions limits. This dispatch can result in the use of the transmission systems in ways that were not envisioned when designed and can cause power flow problems in neighboring systems.

Proposed Clean Air Programs — The federal and provincial governments have proposed a draft NO_x and Volatile Organic Compounds (VOC) Management Plan aimed at capping NO_x and VOC emissions in Canada by 1994 at levels no higher than in 1987. The federal plan could impose a NO_x limit of 0.17 lb/mmBtu on existing fossil units in the southern portions of Ontario, Québec, and British Columbia by 1997, regardless of unit capacity factor, age, or amount of emissions. However, the provinces could use other regulatory means such as emissions caps.

In addition to this federal initiative, Ontario has proposed draft regulations for a Clean Air Plan (CAP) to replace existing Ontario air quality regulations. Other provinces may follow. Emitters will have to reduce high hazard pollutants (such as dioxin and lead) to levels attainable by the best removal technology known anywhere in the world. Medium hazard pollutants, such as NO_x and SO_2, will require reductions attainable by the best available technology that is economically achievable. Local ambient air quality standards will be defined. All emitters will require certificates of approval to operate, and the certificates of approval will be frequently reviewed. Fines will be designed to make it less costly to comply than to pollute.

The impact of these proposed regulations on electric system reliability would be far more severe than the program to date. Key reliability concerns include:

- Capacity shortfalls due to the time required to retrofit emissions control facilities such as selective catalytic reduction systems and scrubbers on existing plants.

- Capacity shortfalls due to the long lead times to implement clean coal or non-fossil resource replacements for existing fossil-fired generating units.

- Increased dependence on natural gas for fuel conversion, combustion turbines, and combined cycle units to reduce NO_x emissions and replace coal-fired capacity, and concerns about fuel supply deliverability as discussed in the "Fuel Supply Adequacy" chapter.

- Environmental dispatch and electricity purchases from neighboring systems further stressing the transmission systems.

Both the provincial Clean Air Plan and the federal NO_x/VOC Plan are very severe regulations as proposed, but are subject to further discussion. Ontario Hydro is proposing that the benefits and costs of emissions controls be reviewed prior to implementation, that a unit's capacity factor and age be taken into account, that realistic schedules be incorporated, and that a NO_x trading scheme be permitted in these new regulations.

Fuel Supply Adequacy

An adequate supply of fuel for existing and planned generating capacity is basic to the reliability of the electric systems in NERC.

Significantly increased use of natural gas for electricity generation is developing in several Regions where electric utilities have not traditionally been major users of natural gas. Serious concerns exist as to the availability of fuel supply to both utility and non-utility gas-fired generating capacity, particularly during winter peak demand periods. In addition, careful coordination with gas suppliers will be required if the large number of planned peaking combustion turbines with their sudden, short duration use of only a few hours a day are to be supplied and operated reliably on natural gas.

Dramatically increased demand for low sulfur coal needed to comply with new clean air regulations may exceed mining capabilities in the eastern United States and may strain transportation systems.

Historical Perspective

The energy crisis of the 1970s, symbolized by the long lines at gasoline pumps, highlighted the importance of reliable fuel supplies. To avoid the fuel supply disruptions of the early 1970s, and in response to the Fuel Use Act of 1978 prohibiting the use of natural gas in new utility boilers, electric utility construction emphasized coal-fired power plants.

Demand for oil and natural gas began to decline in the early 1980s, while at the same time, supplies of these fuels increased in response to higher prices. In addition, regulatory, financial, environmental, and economic factors discouraged the construction of new coal-fired and nuclear generating plants.

New issues are emerging regarding the long-term adequacy of the supply and delivery infrastructures associated with natural gas, fuel oil, and low sulfur coal.

Availability of Gas

The total annual consumption of natural gas in the United States was just over 18 trillion cubic feet (Tcf) in 1990. About 3 Tcf was used by electric utilities and non-utility generators (NUGs) for the production of electricity. Natural gas consumption in the United States peaked in the early 1970s at approximately 22 Tcf. Natural gas used for electricity generation also peaked in the early 1970s at approximately 4 Tcf.

The use of natural gas by electric utilities in the United States is expected to increase from about 2.5 Tcf to 3.5 Tcf over the forecast period. Approximately 45% of existing and planned NUG capacity is fueled by natural gas. Assuming the same ratio of natural gas consumption to electricity generation for NUGs as for utilities, NUG use of natural gas can be expected to increase to 1 Tcf by the year 2000. Natural gas for electricity generation is, therefore, likely to exceed its previous peak use that occurred in the 1970s. In Canada, natural gas used for electricity generation is projected to increase from the current annual consumption of about 50 billion cubic feet to over 250 billion cubic feet by the end of the forecast period. Actual and projected natural gas consumption for electricity generation in the United States and Canada are shown in Figures 1 and 2, respectively.

Estimates of natural gas reserves vary considerably. Recent U.S. Department of Energy/Energy Information Administration (DOE/EIA) estimates placed proven U.S. reserves at approximately 159 Tcf in 1988. This estimate is a slight decline from the estimates of proven reserves of 169 Tcf in 1981 indicating consumption has exceeded additions to reserves during this period. The greatest uncertainty is associated with the potential undiscovered and unconventional natural gas reserves. DOE and others have estimated these reserves at 500-1000 Tcf. Canada and Mexico also possess large reserves of natural gas. In addition to these reserves is the potential to produce synthetic gas from the vast U.S. reserves of coal and to import liquified natural gas. It is not clear, however, if these reserves will become available in a

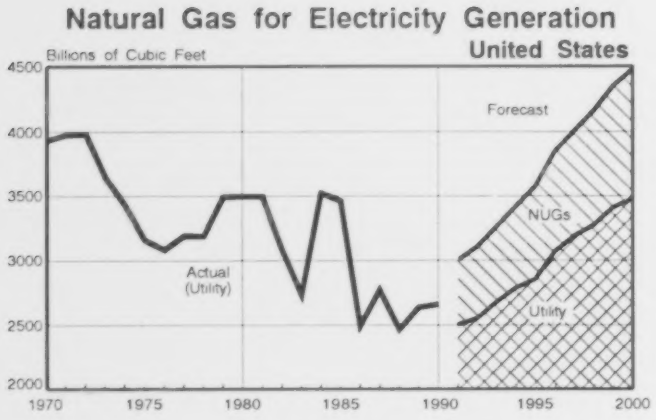


Figure 1

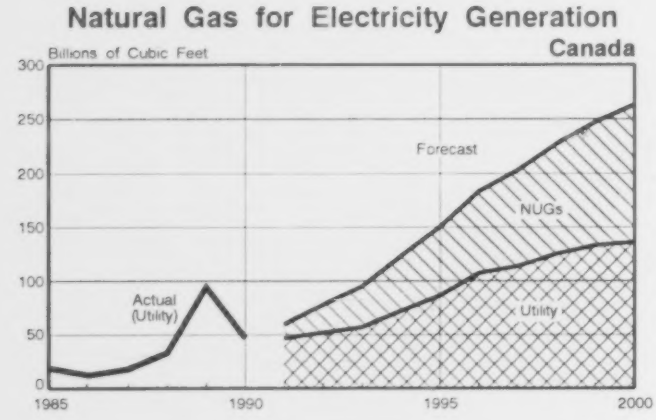


Figure 2

timely way so as to avoid supply disruptions.

Deliverability of Gas

Limitations currently exist in the natural gas delivery system that constrain the use of gas for electricity generation, particularly during winter. These limitations are likely to become more critical as the use of natural gas for electricity generation increases. This concern may prove to be particularly true as much of the increased use is developing in Regions that are remote from natural gas supplies. The gas pipeline systems needed to supply this new demand are, therefore, different from the ones needed to supply the historical demand.

Efforts are under way to improve natural gas delivery. For example, approval was recently received allowing the import of 397 million cubic feet per day of Canadian natural gas into the northeastern United States. This gas will be carried by a new 370-mile pipeline from Canada into Connecticut and New York.

Many electric utilities routinely switch from natural gas to fuel oil in November as increasing heating demands for natural gas strain the delivery systems from the natural gas production areas in the southern and southwestern states. Even in the producing states, natural gas curtailments occur during periods of cold weather as was the case in Texas in December 1989. Several states have regulations that assign priorities to natural gas users. In many instances, electric utilities have the lowest priority and are the first to be curtailed. Switching from natural gas to fuel oil in some cases results in derated unit capacity and operating problems. In addition, the ability to switch from natural gas to oil may be impaired by weather and limited by availability and inventories.

An additional concern is the dependence of many geographical areas on a single pipeline. While pipelines are highly reliable, increasing use of natural gas for electricity generation could lead to the simultaneous loss of large amounts of electrical generation in the event of a pipeline failure. The New York Power Pool is currently investigating the impact of just such a contingency.

Many utilities are planning to install combustion turbines for peaking service. These units may operate for only a few hours a day. This type of sudden, short duration use can cause unacceptable pressure drops on gas pipelines and subsequent loss of electrical generation. Careful coordination with gas suppliers will be required if the large number of planned peaking combustion turbines are to be supplied and operated reliably on natural gas.

Contracts that many NUGs have with their fuel suppliers raise concerns about the NUGs' abilities to supply electricity when needed. Several Regions have experienced problems with NUGs having interruptible gas supply contracts and NUGs not being available during periods of extreme cold weather when customer demand was high and gas

supplies were interrupted. In some cases, NUGs have dual fuel capability, but inadequate or limited fuel storage facilities could impair their availability for extended operation with alternate fuels.

Availability of Oil

World oil consumption is currently about 22 billion barrels annually. Total annual consumption of oil in the United States is approximately 6 billion barrels. U.S. electric utility consumption in 1990 was about 180 million barrels or 3% of total U.S. consumption, a significant decline from the 1978 peak use of 636 million barrels. Use of oil for electricity generation in the United States is projected to decrease from the 1990 level to about 120 million barrels by 1996 and then increase slightly again to about 150 million barrels by 2000. Canadian annual oil requirements for electrical energy production are small (about 19 million barrels) and forecast to remain at the 17-22 million barrel level over the forecast period. Actual and projected oil consumption for electricity generation in the United States and Canada are shown in Figures 3 and 4, respectively.

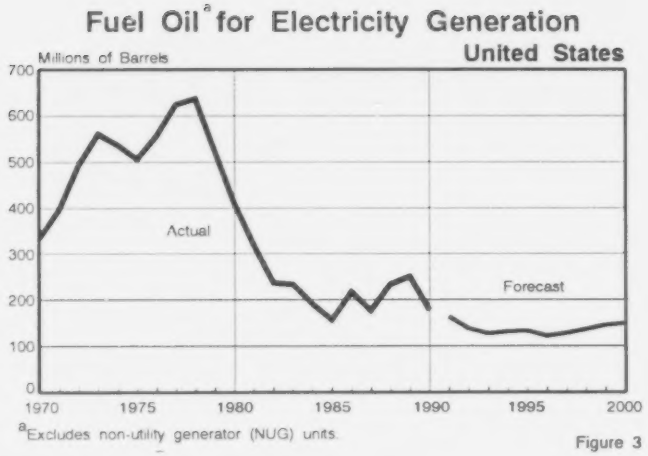


Figure 3

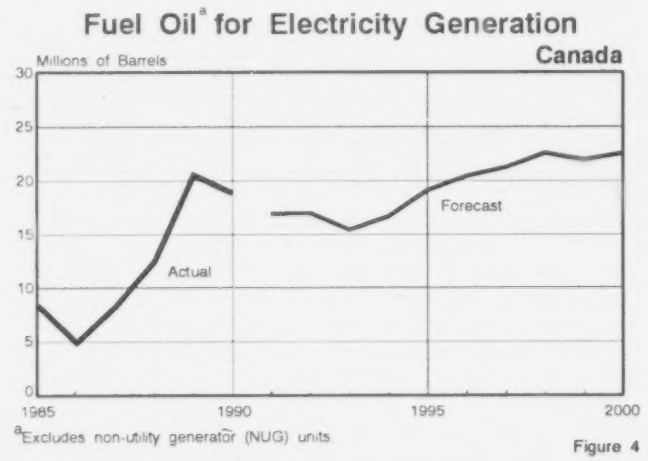


Figure 4

The United States has been importing increasing amounts of its oil requirements since the mid-1980s due to declining domestic production. According to the 1990 National Energy Strategy, the United States is now importing about 42% of the oil it is consuming. The percentage of oil from imports is expected to increase in the 1990s, reaching 57% by 2000. Although fuel oil accounted for only about 3.7% of the electricity generated in the United States in 1990 and utilities use only a small percentage of total U.S. oil requirements, the heavy reliance on imported oil by the United States raises a number of concerns regarding oil's future availability. These concerns include the use of oil as a political weapon, instability in OPEC countries that control 75% of the estimated 800 billion barrels of world conventional crude oil reserves, and the tolerance of the United States for huge trade deficits caused mainly by oil imports.

Deliverability of Oil

The two major types of oil used for electricity generation are No. 6 residual fuel oil and No. 2 distillate fuel oil. Environmental constraints will require the use of low sulfur fuel oil. Low sulfur distillate is available from domestic suppliers. However, for economic reasons, U.S. refining capacity for low sulfur residual oil is limited. Improvements in refining processes have also caused refiners to make more profitable products than No. 6 residual oil. As a result, the domestic supply of low sulfur residual fuel oil is not likely to increase.

In some states, regulatory authorities have placed limits on the amount of fuel inventories allowed in utility rate base, usually on the basis of historical consumption. However, inventories are meant to meet needs during

supply disruptions that could be more severe than historical occurrences. This is particularly true when oil is used to fuel peaking capacity or as a backup fuel for natural gas. In these instances, oil requirements can vary dramatically from year to year and season to season and the rate of use may exceed the capability of supply. Maintaining adequate inventories is essential to provide reliable electric service.

Regional Dependence on Oil and Gas

Fuel mix statistics for electricity on a national basis do not reveal Regional trends or reliability concerns. Fuel mixes, as with generating capacity, vary greatly among the Regions. Use of fuel oil and natural gas for electricity generation by Region for 1990 and 2000 is shown in Tables 2 and 3, respectively. NPCC-U.S. is the area most dependent on fuel oil followed by SERC and MAAC. Similarly, WSCC, ERCOT, and SPP will be the Regions most dependent on natural gas.

Availability of Low Sulfur Coal

Adequate supplies of low sulfur coal may not be available in a timely manner to meet the increased demands caused by clean air legislation. This increased demand is likely to strain low sulfur coal mining capacity in the eastern United States as well as transportation systems in both the East and the West.

The mining capacity for low sulfur Eastern coal may not be adequate to meet demand, and this could lead to significant use of Western coal in eastern and mid-western Regions. Use of low sulfur Western coal in place of Eastern coal will pose significant problems of transportation and supply for some Regions. Such dramatic changes to the complex network of coal mining and transportation raise significant concerns about the potential for coal supply shortages. See the "Clean Air Regulations" chapter for additional information on the availability of low sulfur coal.

Fuel Oil[a] for Electricity Generation

Region	1990 Actual		2000 Projected	
	Millions of Barrels	% Electricity Generation[b]	Millions of Barrels	% Electricity Generation[b]
ECAR	1.1	0.1	3.2	0.3
ERCOT	0.8	0.1	1.2	0.2
MAAC	19.2	4.8	31.4	6.5
MAIN	2.3	0.2	4.8	1.2
MAPP	0.4	0.1	1.1	0.2
NPCC	99.7	26.4	70.3	16.1
SERC	43.7	4.2	34.3	2.7
SPP	1.9	0.4	0.9	0.2
WSCC	8.8	0.8	1.9	0.2
United States	**177.9**	**3.7**	**149.1**	**2.6**
MAPP	0.0	0.0	0.0	0.0
NPCC	18.8	4.3	22.5	2.7
WSCC	0.0	0.0	0.0	0.0
Canada	**18.8**	**2.9**	**22.5**	**2.0**

[a]Excludes non-utility generator (NUG) units.
[b]Percent of each area's respective annual electricity generation.

Table 2

Natural Gas[a] for Electricity Generation

Region	1990 Actual		2000 Projected	
	Billions of Cubic Feet	% Electricity Generation[b]	Billions of Cubic Feet	% Electricity Generation[b]
ECAR	6.9	0.1	47.0	0.7
ERCOT	825.0	39.2	895.1	33.4
MAAC	77.3	2.7	150.7	6.0
MAIN	9.7	0.4	39.5	1.3
MAPP	9.6	0.4	21.6	0.9
NPCC	291.1	11.3	249.9	9.6
SERC	219.2	3.4	369.4	4.5
SPP	672.4	25.7	829.8	26.4
WSCC	548.4	9.9	877.0	14.0
United States	**2659.6**	**9.0**	**3480.0**	**9.9**
MAPP	8.2	1.7	8.4	1.4
NPCC	0.0	0.0	0.0	0.0
WSCC	38.6	3.9	127.7	10.4
Canada	**46.8**	**1.1**	**136.1**	**2.2**

[a]Excludes non-utility generator (NUG) units.
[b]Percent of each area's respective annual electricity generation.

Table 3

Operating Complexities

Operation of the electric systems has changed significantly over the last ten years and is likely to change as much or more over the next ten.

Projected additional complexities include: the availability of emergency generation assistance under the clean air regulations, the need to further increase environmental considerations in generation economic dispatch schedules while maintaining system reliability, the proliferation of non-utility generators, additional electricity interchange schedules created by increased transmission services, and increased line loadings in portions of the transmission systems.

Although utility system operators are committed to "keeping the lights on," future complexities must be responsibly managed if the reliability of electric supply is to be maintained. System operators, working together, will meet the challenges through improved technology and training, increased operating skills, and a continued commitment to electric system, Regional Reliability Council, and NERC operating reliability criteria and guides.

System Operations

Operation of the electric systems has changed significantly over the last ten years and is likely to change as much or more over the next ten. Changes brought about by regulatory constraints, increasing competition, decreasing transmission flexibility, and growing environmental concerns have created a very different operating environment.

These changes along with the effects of new clean air regulations, the proliferation of non-utility generators, the added electricity interchange schedules created by increased transmission services, and increased transmission line loadings in portions of the transmission systems present many new operating complexities to electric system operators.

Effects of Clean Air Regulations

The implementation of existing and new clean air regulations in the United States and Canada, as discussed earlier in this report in the "Clean Air Regulations" chapter, will present a number of challenges to electric system operators.

Limitations on Generation Supply and Assistance — Clean air regulations, by restricting air emissions, will limit the amount of electricity that some fossil-fired generating units will be able to produce. This could result in shutting down generators to stay within a utility's emissions limits and thereby avoid clean air legislated civil and/or criminal penalties. If this scenario were to occur, it could be impossible to meet customer demands unless emergency generation assistance from neighboring utilities is available.

The availability of emergency assistance will also be affected. Before helping other utilities, system operators will consider whether they will be able to remain within their own emissions limits. Considering the penalties their utilities could face, system operators may not be willing to provide assistance if it would place their own customers — or corporate executives — in jeopardy. Thus, the utility in need may be forced to interrupt electric supply to its customers even though generating capacity is available but limited by emissions constraints. This potential limitation on emergency generation assistance will be a major complexity that system operators have never previously had to face.

More Expensive Operations-Environmental Dispatch — Electric utilities minimize the cost of the electricity supplied to their customers by economically dispatching their generating units and purchasing electricity from other utilities, when it is less expensive than generating it themselves. Traditionally, economics have been optimized within the constraints of maintaining adequate reliability. Computers calculate and control the sources of electrical supply in a priority that will

meet customer demands in the most economic manner within prescribed operating reliability criteria. The emissions limits imposed by clean air regulations add another dimension of constraints — further environmental considerations — to this dispatch equation. Because any constraints added to the economic dispatch equation will result in less economical electricity production, the new emissions limits will cause electricity generation costs to rise.

Changes in Transmission System Use — Some utilities are making significant purchases of electricity from other utilities to the point that they are approaching limits in portions of the existing transmission systems to accommodate these economic transactions. Utilities have been able to do this reliably through increased use of innovative operating tools, such as nomograms to determine simultaneous electricity transfer limits, special operating procedures that call for adjustments to electricity transfers during critical operating situations, and sophisticated special protection systems. As transmission loadings are pushed to higher levels, however, more variables must be considered to sustain reliable operations. System operators are being trained to develop the skills necessary to understand the implications of higher transmission loadings and to avoid serious system conditions, such as voltage collapse.

Compliance with clean air regulations can significantly increase or alter the loading patterns on the transmission systems. The transmission systems have been planned and designed to operate reliably. The assumptions used to choose the "best" plan and design have included generation dispatch patterns based on economics and reliability criteria prior to the clean air regulations. These regulations will likely change the economic generation dispatch patterns as well as the sale and purchase of electrical energy.

The Good and Bad News NUGs

The increasing number of non-utility generators (NUGs) will create additional challenges for system operators. Utilities view NUGs with mixed emotions. Some NUGs are considered as welcomed relief from capacity deficiency problems, while others are considered a major burden because of the NUG's electrical energy that the utility must buy whenever it is available and the inability of the utility to control NUG operations. In the former case, NUGs help to supply needed generating capacity to meet growing customer demands. Through contract negotiation, the non-utility capacity is operated and controlled much like the utility's own capacity and has been reliably integrated into the utility system. In the latter case, utility operators, particularly during light customer demand periods, are faced with absorbing unneeded NUG electrical energy into their systems even to the extent of forcing utility baseload coal and nuclear units into uneconomic operation.

Other problems occur when NUG capacity is located where it is not needed and where existing transmission lines are not capable of accommodating the capacity. For example, the proliferation of wind generators in California has resulted in severe transmission line overloads on several occasions. Transmission lines are designed and built to handle electrical energy for serving projected customer demands and with lim-

NERC Operating Committee

The NERC Operating Committee is responsible for promoting reliability in the operation of the interconnected electric systems and for providing a mechanism for the coordination of that operation. It develops the Operating Reliability Criteria and Guides, approved by the Regions, that serve as a basis for good system operating practices.

The Committee is comprised of at least two experienced operations representatives from each of the nine Regional Reliability Councils. Its work is accomplished by a number of subcommittees and working groups. Three subgroups are described below.

*The **Monitoring Working Group**, at the request of a utility, reviews control area operations for conformance to the NERC Operating Reliability Criteria and Guides. To date, the Group has reviewed 55 control areas, including three Alaskan systems.*

*The **Performance Subcommittee** establishes control performance guidelines and measures performance. One of its most important functions is monitoring the control performance of the some 150 control areas in the United States and Canada.*

*The **Disturbance Analysis Working Group** reviews major electric system disturbances and issues an annual report of its conclusions. This report supplies information on what caused the disturbances and provides others with lessons learned so they can take steps to avoid similar problems.*

ited capability for system emergencies. The electric systems cannot always accommodate unsolicited additions of NUG generator units, which can threaten the reliability of the transmission network.

The operator's interface with the NUGs is generally governed by contractual arrangements, each different from the others. Therefore, system operators cannot dispatch NUG units like their own due to the many contract considerations. This adds another complexity to the operator's responsibility of keeping economics and reliability in balance.

Closely related are the increased electricity interchange scheduling requirements for NUGs and wholesale customers, which purchase electricity from remote suppliers (other control areas). In many cases, the host utility where the NUG is located is not the purchaser of the NUG electricity. However, the host system operator must arrange to schedule and transfer the NUG generated electricity to the purchasing system and, in some instances, provide backup electrical energy if the NUG unit is forced out of service.

These new players in the utilities' interconnected network place significant burdens on system operators, particularly when a great number of them are in one host control area. The need to determine generator dispatch schedules, minimum generator operating levels, and third-party transmission service (wheeling) arrangements, and to keep all of these in line with the electricity interchange contracts, sometimes gets to be extremely complicated. During emergencies, these complications could jeopardize the reliable operation of the electric systems.

In 1987, NERC published its reference document *Reliability Considerations for Integrating Non-Utility Generating Facilities With the Bulk Electric Systems* as a guide for utilities and NUGs. This document explains the principal requirements embodied in the planning and operating reliability criteria that utilities and NUGs must follow to ensure a reliable electric supply, and should be a part of the interconnection agreements between the utility and NUG.

NERC Operating Reliability Criteria and Guides

All operators of generating capacity connected to the interconnected networks must be aware of and make every effort to abide by the NERC Operating Reliability Criteria and Guides. The NERC Operating Manual contains the NERC "Reliability Criteria for Interconnected Systems Operation" (Criteria) and the NERC "Operating Guides" (Guides), which are designed to promote reliable operation among interconnected systems and to achieve a high level of interconnected system reliability and control. The Criteria establish the basic operating policy, and the Guides specify how this policy is to be implemented. The Criteria and Guides are based on established technical rationale and mature operating experience and judgment. They are reviewed and updated as necessary by the Operating Committee with consideration for both present and future interconnected operating requirements.

Control Area

A control area is an electric system, or group of systems, that regulates its electricity generation to maintain its electrical energy interchange schedule with other systems, contributes to frequency regulation of the interconnected network, and fulfills its obligations and responsibilities in accordance with NERC and Regional requirements.

Approximately 150 control areas in the nine Regional Reliability Councils adhere to the NERC Operating Reliability Criteria and Guides. They also adhere to other requirements imposed by Regional Reliability Councils, power pools, or other associations.

Future Operations

System operations are becoming more complex. Utility operators will continue to work together to manage the challenges to reliable operations through improved technology and training, increased operating skills, and a continued commitment to electric system, Regional Reliability Council, and NERC operating reliability criteria and guides.

Although the operators are committed to "keeping the lights on," the existing and new challenges must be responsibly managed if reliability is to be maintained. The key to preventing a decrease in reliability is for all who have significant influence — electric utilities, regulators, government, and non-utility generator entrepreneurs — to make reliability of electric supply to the customer a dominant common goal.

Transmission Siting and Services

The ability of the electric utilities to add transmission facilities in a timely manner is uncertain. The growing obstacles to the siting and certification of new lines could make necessary expansion of the transmission systems extremely difficult.

One of the key issues affecting transmission line siting and certification is electric and magnetic fields (EMF). To date, no consensus among scientific researchers exists as to whether or not there are adverse health effects due to EMF associated with the installation and use of electrical equipment. This lack of consensus has resulted in inquiries by the public and regulatory bodies that have delayed the construction of new transmission facilities. Intensive research, by electric utilities and others, is under way regarding health effects of EMF. Until such research demonstrates whether or not there are adverse effects, EMF will continue to be a significant issue in the approvals process for siting and routing transmission facilities.

Demands for transmission services are increasing, including legislative proposals for mandated transmission services. These additional services in many cases can only be accommodated by expanding the transmission systems, or by imposing the additional uses on the existing systems and incurring a reduction in bulk electric system reliability. All users of the transmission systems must adhere to applicable electric system, Regional Reliability Council, and NERC reliability criteria, policies, and guides if electric system reliability is to be maintained.

Transmission Siting

In most areas of the United States and Canada, the approvals process for siting and certifying major transmission facilities provides a structured forum in which to debate issues related to the proposed facilities. This process, however, has led to significant delays of key transmission lines. Reliability concerns exist in certain areas of MAAC and MAIN, where transmission facilities have not been allowed to be constructed as planned.

MAAC — General opposition to the construction of new transmission within the MAAC Region is of concern. Despite recent progress in overcoming obstacles in the approvals process, the long delay in completion of the **Baltimore-Washington 500 kV loop** stands as a classic example of the inability of U.S. utilities to receive timely approval to build critical transmission facilities. The final segment of this project, originally scheduled for 1974, is now scheduled for completion in 1994. Had the full Baltimore-Washington 500 kV loop been in service on July 5, 1990, when peak customer demands and outages of key generating facilities in the Baltimore-Washington area combined to stress transmission capabilities, it is considerably less likely that the affected utilities would have had to implement customer supply interruptions totalling 400 MW to maintain system reliability.

MAIN — The **Albion-E. West Frankfort 345 kV line** was originally scheduled for completion in 1990. However, due to a lengthy regulatory approvals process, court action required before condemnation, and potential future court actions, the line will probably not be placed in service until 1993. This line will constitute a third 345 kV circuit across southern Illinois and is needed to reinforce the electric supply capability to a large area of southeastern Illinois. Another example of delay is the **Burnham-Taylor 345 kV line**, which was originally scheduled for completion in May

1991. This line, critical to the reliability of service to downtown Chicago, has been delayed one year by local permitting problems.

Electric and Magnetic Fields (EMF)

Regulatory and judicial inquiry regarding a possible correlation between electric and magnetic fields (EMF) from power lines and health effects has resulted in the delay or cancellation of some planned transmission facilities and the removal from service of some existing facilities.

Electric and magnetic fields are created whenever electrical devices are energized and used. These electrical devices include home wiring and appliances, computers and other office equipment, industrial machinery, and electric distribution, transmission, and generation facilities. Controversy is ongoing regarding a possible correlation between EMF and adverse health effects. These health effect concerns have surfaced in many states and provinces. Standards for EMF are in the early stages of development.

Historical Background — Much of the public's concern regarding EMF stems from a report, published in 1979, on an epidemiological study conducted in Denver, Colorado that suggested an association between childhood leukemia and proximity to electric distribution wires. However, no actual EMF exposures were measured or calculated. Rather, the proximity to electric distribution wires was used as a surrogate for the strength of the magnetic fields. It is generally accepted that this analysis did not establish a causal relationship between EMF and adverse health effects.

In the twelve years that have elapsed since the publication of this epidemiological study, a wide range of EMF related research activities has been launched. These activities involve more thorough epidemiological studies of childhood leukemia and occupational studies of adult cancer, and scientific investigations of biological effects conducted under controlled laboratory conditions. To date, a number of these scientific studies have been completed, many more are currently under way, and even more have been proposed. It is generally agreed in the scientific community that the emerging evidence no longer allows one to categorically assert that there are no risks associated with EMF, but does not provide a basis for asserting there is a significant risk. The general consensus is that any health effects involving EMF are rare, difficult to detect, and quite subtle, if they exist at all.

Public Response — In the years during which the public's perception of EMF as a possible cause of adverse health effects has grown, this concern has manifested itself in a number of ways that impact an electric utility's ability to install, in a timely manner, the transmission lines needed to maintain the reliability of the interconnected systems. Often, concerns about EMF, raised during the regulatory and judicial review process related to the siting of transmission lines and substations, have resulted in delays or cancellation of planned facilities. Examples include:

- In New Jersey, attempts to prevent a new 230 kV transmission line from being placed in service on the basis of EMF effects delayed the line's initial energization while the regulatory agency conducted a hearing on the issue. The agency ultimately ruled that no causal relationship between EMF from transmission lines and human health had been demonstrated. However, local opposition to the siting of another proposed

Electric and Magnetic Fields

Electric and magnetic fields are forces that are produced by the voltage and current, respectively, in any energized wire or operating electrical device. The combination of electric and magnetic fields is referred to as EMF.

When an electric voltage is applied to a conductor in a wire, an appliance, or other electrical device, it produces an electric field. The strength of the field depends on the magnitude of the voltage, the geometry of the wires, and distance from the wires. Electric fields may be present even though current does not flow. They are generally measured in either volts per meter (V/m) or kilovolts (1,000 volts) per meter (kV/m).

When an electric current flows through a wire to power a toaster, refrigerator, electric motor, or other electrical device, it produces a magnetic field. This characteristic of electricity occurs whether the wire is the cord on a common 110 volt household lamp, a 4,000 volt (or above) distribution line, or a 230,000 volt (or higher) transmission line. The strength of the magnetic field is determined by the magnitude of the electric current flowing through the wires, the geometry of the wires that are conducting the current, and the distance from the wires. Magnetic fields are generally measured in milligauss (mG).

230 kV transmission line on an electrified railroad right-of-way triggered a comprehensive regulatory proceeding on EMF effects.

- In Missouri, the intervention of a city opposed to the siting of a 161 kV transmission line on the basis of EMF effects resulted in the regulatory agency granting a delay in the proceeding to allow consideration of these issues.

Concern about EMF has stimulated the development of EMF standards for transmission lines. Two states have adopted edge of right-of-way EMF strength standards that affect the design of new transmission lines but which are not explicitly applicable to existing lines. However, those opposed to construction challenge such standards on the ground that they are not stringent enough and/or that they should be applicable to existing transmission lines. A number of states are considering the adoption of EMF standards on either a permanent or interim basis. Yet other states have decided that, given the present understanding regarding the relationship between EMF and health effects, there is no scientific basis on which to establish a standard.

Some legislative bodies are considering actions that would restrict or prohibit the construction of transmission lines. Examples include:

- In Rhode Island, companion bills introduced in the state Senate and House of Representatives would impose a three-year moratorium on the construction of new lines at voltages of 60 kV or above to allow research to determine whether exposure to EMF represents a risk to public health. Ordinances containing similar provisions have been enacted in several Rhode Island municipalities.

- In Tennessee, a bill introduced in the state Senate would ban construction of new transmission lines for the next five years. One town has enacted an ordinance that prohibits transmission lines at 120 kV and above from "spilling" EMF beyond the edge of the right-of-way.

- In the state of Washington, a bill introduced in the state House of Representatives would expand existing local oversight for the construction of new transmission lines and substations. In Whatcom County, voters approved an initiative prohibiting construction of new transmission lines above 115 kV except in industrial zones or previously permitted corridors.

- In Louisiana, a parish council adopted a zoning ordinance establishing a hearing and council approval process for any new transmission line at 69 kV or above in a residential neighborhood.

Utility Response — A significant amount of research on EMF is being conducted by the Electric Power Research Institute, which is acting on behalf of and supported by 680 electric utilities. Much additional research is needed before the scientific community can say conclusively whether the EMF experienced by the general public in daily life has any adverse health effects and, if so, the extent of the risks. The role of transmission line-related EMF relative to the other sources of EMF to which the general public is routinely exposed (e.g., household appliances) will also have to be determined.

In response to the EMF concern, electric utilities are selecting transmission line designs and are siting new transmission lines so as to minimize EMF levels. Many utilities have also expanded their efforts to communicate to their customers and the public in general the existing state of knowledge related to EMF, and are providing EMF field measurement services at customer locations.

It will take time for research efforts to produce conclusive results as to whether or not there are any adverse health effects from EMF. In the meanwhile, EMF concerns will continue to be raised during efforts to site new facilities at the very time that increased need for transfer capability and competitive forces in the industry are intensifying the need to expand the transmission systems. The issue of possible adverse health effects due to EMF represents a significant challenge affecting the reliability of the bulk electric systems.

Electric Utility Restructuring

During the decade of the 1980s, encouraged by perceived successes in the deregulation of other industries, policymakers turned their attention to the electric utilities. They determined that the public interest would be better served if the need for new electrical generating capacity were met by non-regulated, non-utility generator (NUG) entities competing head-to-head in a free market environment with regulated electric utilities.

The implementation of these policies had a profound effect on the utilities. By the beginning of the 1990s, NUGs represented a significant percentage of planned generating units in a number of areas of the United States. This

rapid and radical transformation placed additional demands on the transmission networks as developers of NUGs sought to use the transmission systems owned by electric utilities.

As dramatic as these changes have been, the electric utilities are on the verge of a more far-reaching restructuring of the generation sector if the U.S. Public Utility Holding Company Act is revised to facilitate the development of another type of NUG entity, the "exempt wholesale generator." Heightened competition in the generation sector will increase the demands for transmission services on systems that are already loaded to their safe limits in many parts of the United States.

Transmission Services

Demands for transmission services are increasing, including legislative proposals for mandated transmission services. The degree to which utilities may be required to provide transmission services for others (both utilities and non-utilities) is an issue that potentially threatens future electric system reliability. Specific reliability concerns include increased transmission system loadings in some areas, reduced transmission capability margins, and increased coordination problems. Unfortunately, the public debate on transmission services primarily dwells on economic considerations. Serious discussion of reliability issues is often overlooked.

The transmission systems in many areas are now operated at their transfer capability limits. Consequently, additional transmission services in many cases can only be accommodated by expanding the transmission systems, or by imposing the additional uses on the existing systems and incurring a reduction in bulk electric system reliability.

Transmission systems were not designed to provide unlimited transmission service for all parties. It is imperative that any future policies regarding use of the transmission systems recognize the need to maintain adequate electric system reliability.

All users of the transmission systems must adhere to accepted planning and operating policies and practices designed to maintain electric system reliability. These "rules of the road" are described in NERC reliability criteria, policies, and guides and in a 1989 NERC report, *Electricity Transfers and Reliability*, as well as in Regional Reliability Council and individual electric system reliability criteria and guides.

Changing Business Environment

Economic and other pressures, both external and internal, are at work recasting the way electric utilities do business. Uncertainties regarding electricity demand, generation, and transmission issues are increasing.

As dependence on non-traditional resource options such as non-utility generators and demand-side management increases, electric utilities will be faced with the challenge of maintaining reliability with increasing amounts of resources not under direct utility control. In addition, mandatory inclusion of non-traditional and subjective variables such as "environmental externalities" and "societal costs" in the economic evaluations of alternative generation and transmission proposals further clouds the planning process.

Regulatory impediments continue to be a major source of disincentives to the electric utilities' maintenance of electric system reliability. However, some encouraging signs can be found as regulators and electric utilities reevaluate their respective roles to determine how they can more productively interact. A balanced approach to future system development must be maintained in which electric system reliability, the environment, economics, and the public interest are considered in a rational and timely review process.

Industry in Transition

Electric utilities are in transition. Economic and other pressures, both external and internal, are at work recasting the way electric utilities do business. At the same time, our society has never been more dependent on a reliable supply of electricity.

The deregulation of segments of electric utility operations, the economically induced down-sizing of utility companies, and the growing pressures of competitive forces are moving the electric utilities toward a new entrepreneurial outlook that may be in conflict with their long-standing public service role. In addition, proposed revisions to the U.S. Public Utility Holding Company Act have the potential to further change the infrastructure and operation of the electric utilities as they exist today. These complications and uncertainties all translate into possible threats to electric system reliability.

Electricity Demands — Uncertainties exist regarding the long-term effectiveness of conservation measures and other utility-sponsored demand-side management programs. These uncertainties make the task of accurately projecting future electricity demand more difficult.

Generation — In the electric supply arena, new classes of producers vie for competitive advantage. The emergence of non-utility generators (NUGs), fostered in some instances by regulatory-imposed competitive bidding programs, greatly complicates the planning of generating capacity resources. The mandatory inclusion of non-traditional and subjective variables such as "environmental externalities" and "societal costs" in economic evaluations of alternative generation, as well as transmission, proposals further clouds the planning process.

Transmission — The operation of the interconnected transmission systems is being affected by pressures for increased use of utility-owned transmission facilities by non-owners. The critical role that a strong, flexible transmission system plays in providing reliable service must always be recognized when considering transmission use issues.

Utility Responses — The general reactions of electric utilities to these changing conditions have been to adopt strategies that avoid large capital expenditures for ma-

jor projects, especially large generating units. Most utilities have shifted toward increased reliance on short lead-time resource options, and a "just-in-time" inventory approach to generating resource adequacy. The growing dependence on NUGS, demand-side management, and other non-traditional resource options, however, creates unquantifiable risks.

Reliability will no longer be based solely on utility hardware, but will be increasingly dependent on contractual relationships with generating resources of non-utility organizations outside the utility's direct control and on changes in customer behavior and lifestyles associated with demand-side management options. The challenge will be to maintain reliability with increasing amounts of resources not under direct utility control.

Discouraging Signs

Against this backdrop of change, regulatory impediments continue to be a major source of disincentives to electric utilities' maintenance of reliability. Some of these disincentives are discussed below.

Financial Disincentives — Perhaps the most pervasive impediments during recent years have been regulatory disallowances of full recovery of utility investments. After-the-fact prudency reviews and inadequate or significantly delayed rate increases create powerful financial disincentives that can cause utilities to be unable or unwilling to commit to needed projects because of the associated financial risk.

- Commonwealth Edison Company was recently granted rate increases associated with its Byron 2 and Braidwood 1 and 2 nuclear units that were placed in service in the late 1980s. The company had been carrying the $7.1 billion cost of these units for approximately three years without having the costs reflected in its rates.

- The Louisiana Court of Appeals increased the $135 million disallowance that the New Orleans City Council had imposed on New Orleans Public Service Inc.'s $1.6 billion investment in the Grand Gulf 1 nuclear unit by $341 million. The court noted in its ruling that the financial solvency of a regulated public utility should not be considered when determining disallowances.

- An Illinois Appeals Court recently found that the Illinois Commerce Commission erred in using the needed and economic benefits tests in determining whether and/or what portion of the Clinton nuclear unit was "used and useful." These tests, which were incorporated in the Commission's 1989 rate order, resulted in only 27% of Clinton being "used and useful." The Illinois Appeals Court's decision is being cited by Illinois Power in support for recovering the remaining prudently incurred costs associated with the Clinton Power Station, which became operational in 1987.

- Standard & Poor's has indicated that reliance on non-utility generators for a significant portion (i.e., greater than 10%) of an electric utility's total generating capacity could adversely affect that utility's credit rating.

- The lack of timely rate relief, stemming from a now rescinded state law that barred recovery for construction work in progress costs, drove the Public Service Company of New Hampshire into bankruptcy in 1989.

Regulatory Delays — Regulatory and siting proceedings that unduly delay or deny needed facilities also adversely affect electric system reliability. These decisions can at times be based on short-sighted assessments and be influenced by those who have little or no stake in the long-term effects.

- The Baltimore-Washington 500 kV loop is a classic example of the inability of U.S. utilities to receive timely approval of critical transmission facilities. This project originally scheduled for 1974 is now scheduled for completion in 1994.

- In Ontario, the Environmental Assessment Act established a certification process without time limits on governmental reviews, public hearings, or court challenges.

- The Ontario Intervenor Funding Act of 1988 has created a significant financial burden and increased both the duration and scope of environmental hearings for Ontario Hydro. The hearing on Ontario Hydro's Demand/Supply Plan, which was submitted to the Ontario government in December 1989, did not start until April 1991 due to the delay associated with Intervenor Funding hearings and is expected to continue for two years due to the large number of intervenors.

Overlapping Jurisdiction — Federal versus state, federal versus provincial, state versus state, and other jurisdictional disputes can exacerbate the already lengthy process of navigating a generation or transmission project

through the maze of often overlapping regulations. In the changing utility environment, the potential for jurisdictional disputes and resulting project delays will increase as regulatory agencies redefine their respective roles.

- Uncertainty regarding the applicability of market-based rates and the requirements to mitigate market power have put state regulators at odds with the U.S. Federal Energy Regulatory Commission (FERC) in certain instances. In Nevada, FERC initially overruled, based on lack of sufficient competition, a negotiated market-priced capacity contract between Nevada Power and Sun-Peak, an independent power producer, that was previously approved by the Nevada Public Service Commission under its least cost planning process. Subsequently, FERC approved this much needed capacity contract with cost-based rates.

- In Florida, FERC rejected a market-priced capacity contract involving Tampa Electric and the Seminole Electric Cooperative. The contract, which had been executed under Seminole's state authorized competitive bidding program, was later approved based on cost-of-service pricing.

Inconsistent Public Policies — Inconsistent public policies make planning for the future reliability of electric supply extremely difficult. Utilities must be able to anticipate, with reasonable certainty, what the regulatory and legislative requirements will be and how they will be applied.

Consistent rulings on individual projects from initial authorization throughout the construction process and into operation are critical. Changes or inconsistently applied policies cause delays and uncertainties, lower reliability, and ultimately increase costs to utility customers.

Numerous other examples of regulatory bottlenecks, imposing unwarranted and costly delays, can be cited. However, the hardest to quantify, and in the final analysis just as damaging to reliability, are the number of worthwhile projects that have been abandoned on the drawing boards due to regulatory disincentives.

Encouraging Signs

It should not be assumed from the aforementioned that all is "gloom and doom" nor that utilities have abandoned out of frustration their commitment to electric system reliability. Rather, there are encouraging developments that indicate some hope for the future. Cognizant of the changes that are taking place in the industry, regulators and electric utilities are reevaluating their respective roles to determine how they can more productively interact.

- In Canada, positive steps are being taken by the Ontario Ministry of Environment to reduce the delays imposed by its reviews of major projects under the Provincial Environmental Assessment Act. In addition, both the federal and Ontario Ministries of Environment are cooperating to reduce jurisdictional overlaps.

- In Georgia, recently approved legislation would enable an electric utility to apply, for a fee, to the Public Service Commission for "pre-certification" of the construction costs for a project in its ten-year resource plan. Recovery of prudently expended construction costs would be guaranteed.

- In Michigan, the Public Service Commission has proposed administrative guidelines aimed at completing all cases that come before it within nine months of their filing date.

- In some cases, a change in the adversarial relationship between regulators and electric utilities is beginning to take place that may have beneficial results. The New England Governors Conference's participation with the New England Power Pool in the assessment of future generating resource needs is one example of a new collaborative regulatory approach.

- Other examples include the innovative approaches being taken by several state regulatory commissions toward ratemaking that encourage utility investments in conservation and other demand-side management programs by allowing cost recovery of the investments and expenses of these programs.

Future Outlook

The changes taking place in the electric utilities and the business environment surrounding them must always be measured against the yardstick of electric system reliability in addition to environmental and economic tests, if the current standard of customer electrical service is to be maintained.

A reaffirmation of the commitment to reliability is needed from the regulators and electric utilities alike. A balanced approach to future system development must be maintained in which electric system reliability, the environment, economics, and the public interest are considered in a rational and timely review process.

Peak Demand Projections

The 1991-2000 aggregated projections of summer peak demand for the United States are slightly lower than last year's projections. A comparison for 1999, the last common year of the last two ten-year forecasts, indicates that the U.S. peak demand has decreased by about 6,200 MW (about 1%). In contrast, the 1991-2000 peak demands for winter peaking Canada are about the same as those projected last year.

Future electricity requirements cannot be predicted precisely. Therefore, utilities continue to monitor electricity use and generally revise their forecasts on an annual basis and their resource plans as needed. In recent years, the differences between forecast and actual peak demands have decreased reflecting a trend toward improved forecast accuracy.

Most Regions are projecting expanded use of demand-side management such as conservation, load management, and interruptible demands. Utilities are committed to the success of their demand-side management programs to help maintain adequate resources. However, the long-term customer acceptance of several of these programs has yet to be established in some areas. Load management and interruptible demands — the direct utility-controlled portions of demand-side management — are expected to increase in the United States from 14,100 MW in the summer of 1991 to 20,900 MW in 2000. Similarly, these direct utility-controlled programs will increase in Canada from 2,400 MW in the winter of 1991/92 to 2,800 MW in 2000/01.

1991-2000 Forecast

The electrical peak demand in the United States is projected to grow at 1.9% per year from 551,500 MW in 1991 to 651,100 MW in 2000. This forecast, as shown in Figure 5, is a slight decrease compared to last year's ten-year forecast. A comparison for 1999, the last common year of these two ten-year forecasts, indicates that the projected U.S. peak demand has decreased by 6,200 MW (about 1%) from the 1990 to the 1991 forecast. The United States is anticipated to continue to be summer peaking over the next ten years with its summer peak demand about 11% greater than its prior winter's peak.

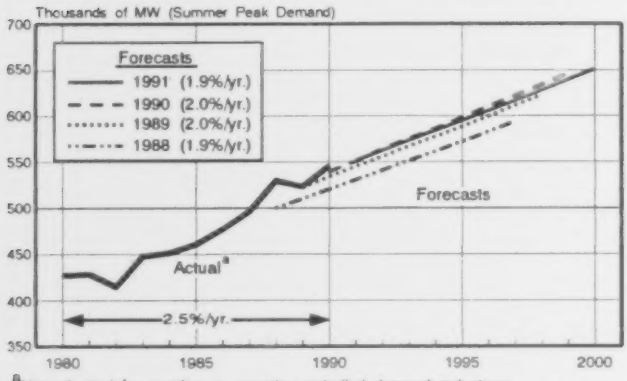
Canada is projected to be winter peaking over the 1991-2000 period with its peak demand growing at 2% per year from 80,900 MW to 97,100 MW. This forecast, as shown in Figure 6, is essentially the same as last year's forecast. Canada's winter peak is expected to exceed its prior summer peak by about 40% throughout the forecast period.

The peak demand and annual net energy for load projections for the United States and Canada are summarized in Table 4. The growth rates for annual net energy for load are slightly higher than the growth rates for peak demand in both countries.

The 1991-2000 projections of peak demand for the United States and Canada and recent actual peak demands are illustrated in Figures 7 and 8, respectively. These base projections have already been reduced by the effects of utility-sponsored indirect demand-side management programs, such as conservation and time-of-use rates. These demand projections can also be further reduced by load management programs and contractually interruptible demands under the control of the utility system operator as indicated in Figures 7 and 8 by the dashed lines, the net peak demands for which generating capacity resources are planned.

The peak demands for the United States and Canada are aggregates of the respective Re-

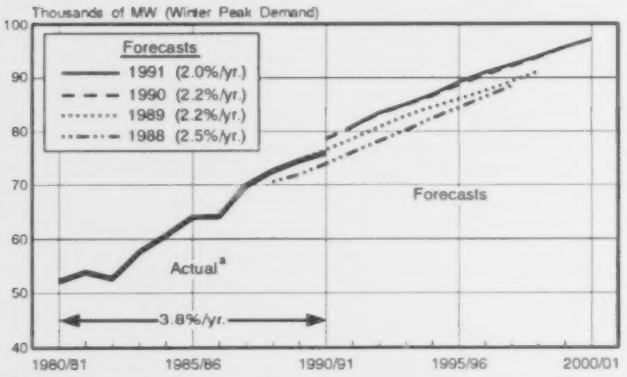
United States – Recent Forecasts



[a]Not adjusted for weather or operator-controlled demand reductions

Figure 5

Canada – Recent Forecasts



[a]Not adjusted for weather or operator-controlled demand reductions

Figure 6

Peak Demands

Forecast peak demands are internal peak demands that have already been reduced to reflect the effects of demand-side management programs, such as conservation and time-of-use rates, not under the direct control of utility system operators. However, these peak demands generally include those customer demands under the direct control or management of utility system operators, such as utility-controlled water heaters and contractually interruptible customers.

The internal peak demand for a system is equal to the sum of the metered (net) power outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system. Thus, internal peak demand is the maximum (hourly integrated) demand of all customer demands plus losses.

gional projections. Three of the nine Regions in the continental United States increased their peak demand projections compared to last year, while three Regional projections remained essentially the same. However, the decreases in the remaining Regions outweighed the increases. Therefore, the U.S. 1991-2000 aggregated peak demand projections are lower than last year's projections. Regional peak demand projections are discussed in the "Regional Reliability Assessments" section of this report.

Forecast Uncertainty

Future electricity requirements cannot be precisely predicted. Peak demand and annual electrical energy are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities. Therefore, utilities continually monitor system peak demands and annual electrical energy requirements and typically update their projections annually. In turn, the utility resource plans are also adjusted as needed.

The peak demand and annual net energy for load projections are aggregates of the forecasts, generally as of January 1991, of the individual utilities comprising the Regional Reliability Councils. These utility forecasts are typically "equal probability" forecasts. That is, there is a 50% chance that the forecast will be exceeded and a 50% chance that the forecast will not be reached.

To avoid implying a degree of certainty not intended in the ten-year forecasts, bands of reasonable variation were developed about the 1991-2000 aggregated peak demand projections for the United States and Canada as shown by the shaded areas in Figures 7 and 8, respectively. For example, the U.S. bandwidth has

been defined such that there is an estimated 80% probability that the future U.S. summer peak demands will fall within the high and low bounds of the bandwidth. This means there is only about a 10% chance that future U.S. summer peak demands in any year will exceed the upper bound of the bandwidth. Similarly, there is only a 10% chance that future demands will be less than the lower bound of the bandwidth.

By the end of the forecast period, the U.S. peak demand in the 80% confidence interval ranges about ±12% around the base 2000 summer projection of 651,100 MW. In Canada, the estimated 80% bandwidth for the 2000/01 winter peak demand ranges about ±15% around the base projection.

It would be incorrect and misleading to apply the absolute value or percentage range of the forecast bandwidths of the United States or Canada to the forecasts of individual Regional Reliability Councils, individual utilities, or groups of utilities because the bands shown represent a composite of all member utilities in each country.

Demand-Side Management

Electric utilities are using and continue to implement demand-side management (DSM) programs, such as conservation, load management, interruptible demands, and other similar programs, to reduce customer peak demands and delay the need for some future generating capacity.

The amount of DSM implicit in the NERC aggregated projections was estimated in 1990 to be the equivalent of about 3% of peak demand in the early 1990s and about 5% by 2000. About a third of these estimates, representing the effects of utility-sponsored indirect DSM programs such as conservation and time-of-use rates, has already been subtracted from the forecast peak demands shown in Table 4 and Figures 7 and 8. The remaining DSM under the direct control of utility system operators — load management and interruptible demands — is summarized in Table 5. The associated demand reductions

Net Energy For Load

The annual net energy for load (NEL) represents the annual electrical energy needed to serve an electric utility's customers. NEL is not just the energy sold to customers, but includes transmission losses. It represents the electrical energy generated by the utility's generating sources plus electrical energy purchases from other electric utilities and non-utility generators, less electrical energy sales to other electric utilities. NEL does not include energy pumping (or charging) requirements for pumped storage (or other energy storage) generating facilities.

Forecast Peak Demand & Energy

	1991	2000	Growth (%/yr)
Peak Demand (Thousands of MW)			
United States — summer	552	651	1.9
Canada — winter	81	97	2.0
Net Energy for Load (Millions of MWh)			
United States — annual	2951	3513	2.0
Canada — annual	446	548	2.3

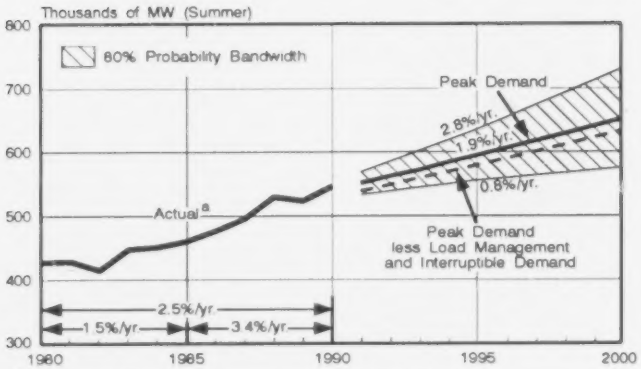
Table 4

Load Management and Interruptible Demands

	1991 Summer		2000 Summer	
Region	Thousands of MW	% Peak Demand	Thousands of MW	% Peak Demand
ECAR	0.8	1.0	1.5	1.6
ERCOT	1.3	3.1	1.3	2.5
MAAC	1.4	3.1	2.3	4.5
MAIN	0.8	2.0	1.4	2.9
MAPP	1.4	4.8	2.6	7.5
NPCC (winter)	2.3	2.2	2.8	2.3
SERC	3.7	3.0	6.6	4.2
SPP	0.6	1.2	1.1	1.8
WSCC	3.8	3.6	4.0	3.1
United States	**14.1**	**2.5**	**20.9**	**3.2**
Canada (winter)	**2.4**	**3.0**	**2.8**	**2.9**

Table 5

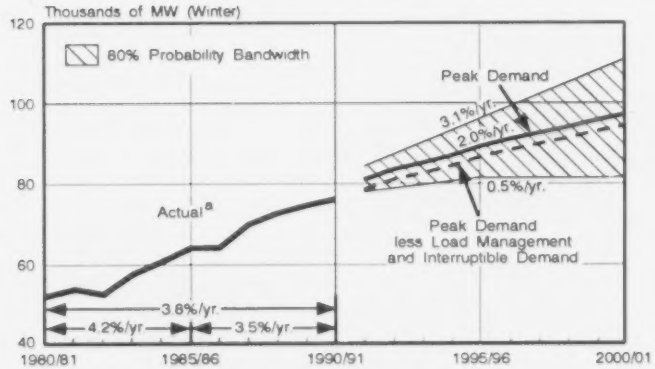
United States – Peak Demands



[a] Not adjusted for weather or operator-controlled demand reductions.

Figure 7

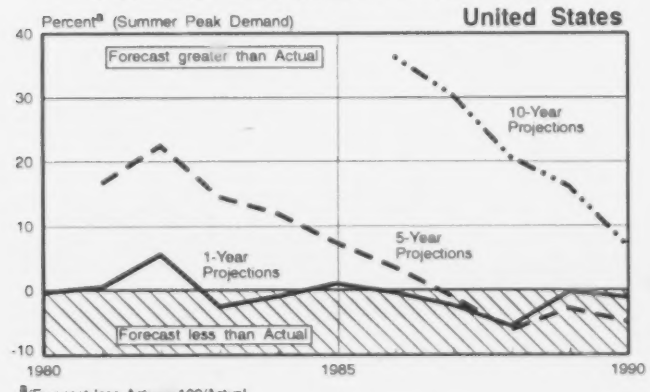
Canada – Peak Demands



[a] Not adjusted for weather or operator-controlled demand reductions.

Figure 8

Forecast Deviations from Actual



[a] (Forecast less Actual)x100/Actual.

Figure 9

projected to be available from these load management and interruptible demand programs at the time of system peak are illustrated in Figures 7 and 8 for the United States and Canada, respectively.

The amount of customer demand under the direct control of utility system operators is uncertain. The demand reduction that can be realized at the particular time when load management is needed and implemented varies with the amount of controllable demand in service at that time.

Utilities are committed to the success of their DSM programs to assist in providing adequate resources to maintain system reliability. However, the long-term customer acceptance of several of these programs has yet to be established in some areas. The concern is that customers, who initially participate in load management and interruptible demand programs because of financial incentives, may decide, once the electric supply to their equipment has actually been interrupted a number of times, that the inconvenience of the interruptions outweighs the cost savings and withdraw from the programs.

Actual Versus Forecast Peak Demands

The 1990 summer peak demand in the United States was 4.2% higher than the 1989 summer peak and 1.2% above the 1990 forecast made one year earlier. Of the nine Regions in the U.S. portion of NERC, only NPCC-U.S. did not exceed its 1989 summer peak demand. Six of the nine Regions in the United States exceeded their 1990 forecast peak demand by 0.4% to 5.7%. In contrast, actual 1990 peak demands in three of the Regions were 0.3% to 6.1% lower than forecast. A summary of this actual peak demand analysis is

Actual Peak Demands

United States (summer)	1989 Actual (Thousands of MW)	1990 Actual (Thousands of MW)	1990 Actual over 1989 (%)	1990 Forecast (Thousands of MW)	1990 Actual over Forecast (%)
ECAR	75.4	79.3	5.1	78.9	0.4
ERCOT	40.4	42.7	5.8	41.9	2.0
MAAC	41.6	42.6	2.4	42.7	−0.3
MAIN	39.5	40.7	3.2	39.2	4.0
MAPP	24.3	25.0	2.7	24.8	1.0
NPCC	45.0	44.1	−2.0	47.0	−6.1
SERC	117.1	121.1	3.5	121.6	−0.4
SPP	49.4	52.5	6.3	51.0	3.0
WSCC	90.7	97.4	7.4	92.2	5.7
Total U.S.	**523.4**	**545.5**	**4.2**	**539.3**	**1.2**
Canada (winter)[a]					
MAPP	6.0	5.9	−1.1	6.0	−0.7
NPCC	54.7	55.0	0.7	58.1	−5.4
WSCC	13.9	15.1	8.9	14.5	4.4
Total Canada	**74.5**	**76.1**	**2.1**	**78.6**	**−3.2**

Note: Actuals are not adjusted for weather or operator-controlled demand reductions.
[a]Winter of 1989/90 and 1990/91.

Table 6

Actual Versus Forecast Peak Demands

Actual peak demands have not been adjusted for variations from normal weather conditions, demand reductions due to load management and interruptible demand actions, or emergency operating procedures that were in effect during the peak hour.

Forecast peak demands are based on the expectation of normal weather conditions, and are not generally reduced to account for direct utility-controlled demand reductions or emergency operating procedures that could be used if required.

Conclusions made from a comparison between actual and forecast peak demands must be made with caution. Adjustments to one or both quantities may be necessary to assure consistent treatment of operator-controlled load management, interruptible demands, emergency operating procedures, and weather.

The process of adjusting actual peak demand to the peak demand that would have been expected if weather conditions were "normal" is called weather-correcting or weather normalization. This is a complex calculation that can result in a lower weather-corrected actual peak demand if weather conditions during the peak were warmer than normal or in a higher weather-corrected actual peak demand if conditions were cooler than normal for summer peaking systems. The opposite effects occur for winter peaking systems.

shown in Table 6 for the United States and Canada.

In Canada, the 1990/91 winter peak was 2.1% above last year's peak, and about 3.2% below forecast. Only the MAPP portion of Canada did not exceed its 1989/90 winter peak, and only the WSCC portion of Canada exceeded its 1990/91 forecast.

The deviations between forecast and actual summer peak demands for the United States are shown in Figure 9 for forecasts made ten and five years as well as one year prior to each specific year. In the aggregate, the U.S. one-year forecasts have been quite accurate since 1983, with the exception of 1988, when summer temperatures were abnormally high. Due to the length of the forecast period and the changing economic conditions, the ten- and five-year forecasts are less accurate than the one-year forecasts, but reflect a trend toward smaller deviations or improved accuracy. In Canada, the one-year deviations between forecast and actual winter peak demands are about the same order of magnitude as summer peak demand deviations in the United States.

Accurate electricity forecasts are particularly important to electric system reliability. Despite the need, accurate forecasts are very difficult to make because they are affected by many factors that cannot be predicted with assured accuracy. Overestimating the demand for electricity will generally result in more than minimum generating capacity margins, which will be advantageous from a system reliability viewpoint. However, underestimating the future demand for electricity can eventually lead to capacity supply shortfalls. The proper timing for DSM programs and generating capacity additions depends on accurate forecasts.

Generation Reliability Assessment

All nine Regions have plans for adequate capacity resources for the 1991-2000 period or are in the process of planning for the additional resources that may be required. These resources will be adequate provided that peak demand growth, the effectiveness of demand-side management programs, and new generating capacity are substantially as projected. However, some areas, all in the Eastern Interconnection, have relatively small margins for contingencies, or are likely to need to rely on capacity resources in addition to those currently planned.

Regional-specific reliability concerns include the uncertain effects of clean air regulations, the availability and deliverability of natural gas for new capacity, the inability to maintain high availability of generating capacity during peak demand periods, the dependability of load management programs, and a heavy reliance on non-utility generators. Other common concerns include higher than expected customer demand growth and timely approvals for capacity additions.

The Eastern Interconnection is particularly susceptible to uncertainties regarding strategies for compliance with new clean air legislation. Compliance plans for many utilities are still in the formative stage. Future available generating capacity may be less than projected due to the addition of emissions control equipment, fuel switching modifications, and currently unplanned retirements.

Method of Analysis

To provide an overview of generation adequacy, a screening analysis was performed in which the projected available capacity resources are compared with projected peak demands. Uncertainties in both of these factors are considered.

More detailed resource adequacy assessments are performed by the Regions, subregions, and individual systems. Those assessments use diverse methods and results cannot be directly compared. The screening analysis in this report provides some comparability for overview purposes. Detailed Regional adequacy assessment results are described in the "Regional Reliability Assessments" section of this report.

Demands used in the screening analysis are discussed in the "Peak Demand Projections" chapter. To simplify the analysis, no peak demand diversity among Regions or subregions is assumed. Weather effects are reflected in the projected peak demands on a statistical basis averaged over time. However, weather extremes could cause peak demands to exceed available capacity resources even though adequate capacity would be available for the more likely weather conditions.

Planned capacity resources also have a range of uncertainty because of possible delays in the construction and start-up of new generator units and the potential effects of evolving environmental regulations on existing and new generating capacity. The range of these capacity uncertainties is reflected as a bandwidth of projected available resources.

Planned capacity resources were reduced to account for generating capacity unavailability at the time of peak demand. In practice, not all installed generating capacity is available at any given time. For this screening assessment, unavailability due to forced outages, deratings, scheduled outages, and other causes is based on recent experience in each Region and subregion. Further, a certain amount of generating capacity needed to accommodate customer demand fluctuations and sudden unit outages is held in spinning reserve. Planned

capacity purchases and sales are included in the analysis, but emergency generation assistance from neighboring Regions is not. Considering all of these factors, the resultant estimate of capacity available to serve peak demand is identified as a bandwidth of "Projected Available Resources" as shown in Figure 10.

The planning of generating capacity is a dynamic activity. Utility supply plans are modified as electricity demand forecasts change. However, recognition of a significant change in demand growth rate must occur soon enough to permit corrective actions, whether they consist of demand-side management activities or the addition of more generating capacity. The lead-time requirements for both short lead-time and baseload capacity additions are also shown in Figure 10.

Interconnections

In the one hundred-year history of the electric utility industry, utilities have grown from isolated systems supplying their customers from local generating sources to highly interconnected systems (or "Interconnections") of generating stations and high voltage transmission lines encompassing large geographic areas and many individual utilities. Today, in NERC, there are four major interconnected areas: the Eastern Interconnection, the Western Interconnection, the Texas Interconnection, and the Québec Interconnection.

Within each Interconnection, individual utility systems are operated in synchronism with each other. Within limits of the transmission systems, demand at any point in an Interconnection can be supplied by generation located at any other point. Transfer of electricity from one point to another will, to some extent, flow over all transmission lines in the Interconnection, not just those in the direct path of the transfer.

The ability to transfer electricity between the Interconnections is very limited, and depends on the capacity of tie lines, the ability to deliver electricity through the network to the tie points, and the amount of generating capacity available at the time of the transfer.

Seven of the nine Regional Reliability Councils (Regions) of NERC comprise the Eastern and Québec Interconnections: ECAR, MAAC, MAIN, MAPP, NPCC, SERC and SPP. The Western Interconnection is the WSCC Region, and the Texas Interconnection is the ERCOT Region.

Interconnection Assessments

An analysis of the adequacy of projected available resources to supply peak demand projections was made for each of the four Interconnections in NERC for both summer and winter peak demand periods. Within these Interconnections, and within transmission constraints, electrical energy may be transferred from an area with available generating capacity to an area with a capacity deficiency. Transfer capability among the Eastern, Western, and Texas Interconnections is very limited, and between the Eastern and Québec Interconnections somewhat limited. The results of the screening reliability assessment analyses are summarized below.

Eastern and Québec Interconnections — The Eastern and Québec Interconnection combination is expected to have sufficient available resources through the year 2000 at expected peak demand and projected available resource levels as shown in Figure 10. However, if peak demand grows faster than projected (i.e., at a growth rate that has a 10% or less chance of occurring), then

additional capacity resources could be needed by 1996. If projected available resources are concurrently at their lowest expected level, additional capacity resources could be needed one year earlier.

The combined Eastern and Québec Interconnections are comprised of seven Regions, each unique in its capacity-demand relationships. The information in Figure 10 is an aggregate of those Regions. Available capacity in one Region may not be fully available to another Region due to transmission limitations, so Regional and subregional assessments are also considered later in this chapter.

Texas and Western Interconnections — The Texas Interconnection (ERCOT Region) and the Western Interconnection (WSCC Region) are projected to have adequate capacity margins at expected demand growth rates and with expected planned capacity resources. More detailed discussions of these Interconnections appear in the ERCOT and WSCC chapters.

Regional Assessments

A review of the "Regional Reliability Assessments" section of the report indicates that all nine Regions are projecting adequate capacity resources or are in the process of planning for additional resources that may be required beyond 1994 to provide reliable electric service to their customers. This review indicates that some areas, shown in Figure 11, have relatively small margins for contingencies, or are likely to need to rely on capacity resources in addition to those currently planned. Regional-specific contingencies and concerns include risks of higher than expected peak demand growth, lower generation availability, or the inability to improve it, especially during peak periods, or the reduced effectiveness of projected demand-side management programs.

In the event that additional resources are required, a portion of them may be obtainable from adjoining Regions or subregions, within the limits of available transmission capabilities. Nevertheless, it appears that if system contingencies occur in these, and possibly other areas, additional internal resources could be needed. Areas with the smallest amounts of capacity available for contingencies are in the Eastern Interconnection. This Interconnection is also the most susceptible to potentially adverse effects from the U.S. Clean Air Act Amendments of 1990.

Eastern & Québec Interconnections Supply Adequacy Assessment

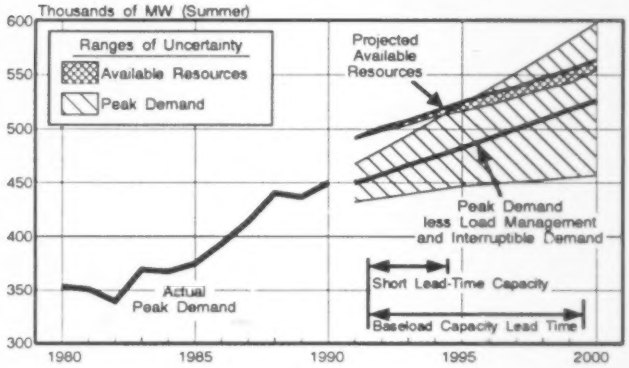


Figure 10

Areas Reporting Tight Capacity Margins

Figure 11

Generating Unit Additions, Changes, and Retirements (1991-2000 Forecast)

Type	United States Thousands of MW	United States % of Total	Canada Thousands of MW	Canada % of Total	NERC-Total[a] Thousands of MW	NERC-Total[a] % of Total
Nuclear	5.9	6.6	2.6	11.5	8.6	7.5
Coal	15.1	17.0	1.9	8.3	17.7	15.6
Hydro	1.1	1.2	12.7	55.0	13.9	12.3
Oil/Gas	34.2	38.3	2.3	9.9	36.8	32.5
Pumped Storage	2.5	2.8	0	0	2.5	2.2
Other (Utility)	12.8	14.3	1.1	4.8	13.9	12.2
NUGs (Net Additions)	17.7	19.8	2.4	10.5	20.1	17.7
Additions	**89.3**	**100**	**23.0**	**100**	**113.4**	**100**
Changes	10.6		0.4		11.0	
Retirements	−4.3		−0.5		−4.8	
Net Total	**95.7**		**22.9**		**119.6**	

[a]Includes additions in WSCC-Mexico.

Table 7

1991-2000 Generating Capacity Projections

New unit capacity additions of 113,400 MW are planned in NERC over the 1991-2000 period. A summary of these generator unit additions, changes, and retirements is shown in Table 7. Utility oil-fired (4,300 MW) and gas-fired (29,900 MW) units account for 38.3% of the total 89,300 MW of planned additions in the United States. The second largest additions in the United States are the non-utility generators at 17,700 MW or 19.8%, nearly half of which are gas-fired. In Canada, hydro units account for 55% or 12,700 MW of the 23,000 MW of total planned additions over the forecast period.

Capacity Resource Concerns

Major concerns about the reliability of planned capacity resources include the effects of clean air regulations, fuel supply adequacy, operating complexities, and the changing business environment. These reliability concerns are discussed in their respective chapters of this report. In addition, other issues that can also affect future generation reliability include:

Peak Demand Exceeding Forecast — In some Regions, projected peak demand growth is below that experienced in the recent past. It is possible that economic growth and/or electricity's share of that growth will be higher than projected. Additionally, the long-term effectiveness and customer acceptance of demand-side management programs, including conservation, in reducing peak demands have not been widely demonstrated. Most Regions are projecting expanded use of utility-controlled load management programs and interruptible demands as a resource to meet future customer peak demands. By the year 2000, load management and interruptible demand programs are projected to be the equivalent of about 3% of the U.S. summer peak demand and about 3% of Canada's winter peak demand.

If sustained peak demand growth is greater than projected, capacity plans will have to be modified. It could take several years to confirm an increase in growth rate. It may then be too late to install baseload generating capacity, as typical baseload capacity lead times are in the range of eight years or more. Utilities may be limited to short lead-time capacity options. Even these may require three years minimum lead time. Siting considerations may preclude a timely response. Also, current U.S. plans include the addition of 30,380 MW of short lead-time utility capacity, primarily combustion turbines. A flurry of further orders for a particular delivery time may strain the ability of manufacturers to produce the equipment as needed.

Trends in Generating Capacity Availability — Maintaining high generating capacity availability during peak demand periods is a critical element in reliability of supply. In many systems, availability has been improving. Several Regions project continuing improvement in on-peak availability. It is important that the improvements being achieved are maintained so that the need for added capacity resources can be minimized.

Reliance on NUGs — Utilities are increasingly relying on non-utility generators (NUGs) as a supply resource. The impact of NUGs is not uniform across the United States. A significant amount of existing U.S. NUG capacity is in California, Texas, and New York. The 1991-2000 projections for NUG capacity show major increases in NPCC, SERC, WSCC, and MAAC. These ten-year projections and total installed NUG capacity by the summer of 2000 in the United States, Canada, and the Regions are shown in Table 8.

In MAAC, 3,393 MW or about 37% of its capacity additions over the 1991-2000 period are projected to be NUGs. Similarly, 8,579 MW in NPCC (32% of its

Projected NUG Capacity

	1991-2000 Additions (MW)	Summer 2000 Total (MW)	Summer 2000 % Capacity Resources
ECAR	1344	3254	3.0
ERCOT	-2106[a]	1090	1.8
MAAC	3393	4858	7.8
MAIN	0	140	0.3
MAPP	74	391	0.9
NPCC	8579	10094	7.0
SERC	4530	6262	3.4
SPP	400	551	0.7
WSCC	3887	11390	7.1
U. S.	**17680**	**35352**	**4.5**
Canada	**2422**	**2678**	**2.5**

[a]Decrease is due to contract expirations. Some capacity may be available under future contracts.

Table 8

planned capacity additions) and 3,887 MW in WSCC (31% of its planned capacity additions) are projected to be NUG capacity. NUG additions in SERC at 4,530 MW account for about 13% of its 1991-2000 planned capacity additions. With increasing dependence on NUGs, utilities are carefully assessing the amount of this capacity that will actually be available to serve future customer demands.

NUG plans and commitments are not always realized. NUG owners are not immune to similar problems faced by electric utilities in getting generating units sited, permitted, constructed, tested, and on-line as scheduled. Other utility reliability concerns with NUGs are their dispatch control, availability, and service life.

Unspecified or Unknown Capacity — A review of recent ten-year forecasts shows that unspecified or unknown planned capacity additions have increased in the United States to 14,500 MW (about 16% of total planned additions) and in Canada to 2,300 MW (10% of total additions). This unspecified capacity is due in part to the reliance by many utilities on short lead-time capacity supply options, a large portion of which are unspecified NUGs. Permitting and certification lead times must allow commitment to a specific capacity supply option in time to assure that the option is available for service when needed.

Units Not Yet Under Construction — A review of projected capacity additions reported in the last six ten-year forecasts indicates a steady increase, particularly in the United States, in the amount of generating capacity not under construction at the beginning of each forecast period. This trend can be expected, as previously committed longer lead-time units are being completed and the mix of future units is tending toward shorter lead-time options. However, there is concern about the increasing amount of generating capacity additions scheduled for near-term service, within the first two to five years of the forecast period, that are not under construction.

About 66,400 MW or 72% of the total planned additions in the United States and Canada consist of utility units that are not yet under construction. Of this amount, about 32,630 MW consist of combustion turbines, jet engines, and internal combustion (diesel) units, all of which are generally short lead-time generator additions. The remaining 33,770 MW include both longer lead-time types of capacity and capacity of unspecified type.

Figure 12 indicates that about 3,900 MW of the longer lead-time capacity in the United States have projected in-service dates of 1995 or earlier, and about 2,100 MW of the short lead-time capacity not yet under construction have projected in-service dates of 1993 or earlier. In addition, about 7,000 MW of U.S. NUG capacity of various sizes, scheduled for service by 1993, are not reported to be under construction. Recognizing typical lead-time requirements, it is possible that some of this capacity, planned for the near term but not identified as being under construction, will not be completed on schedule.

U.S. Utility Generator Unit Additions Not Yet Under Construction

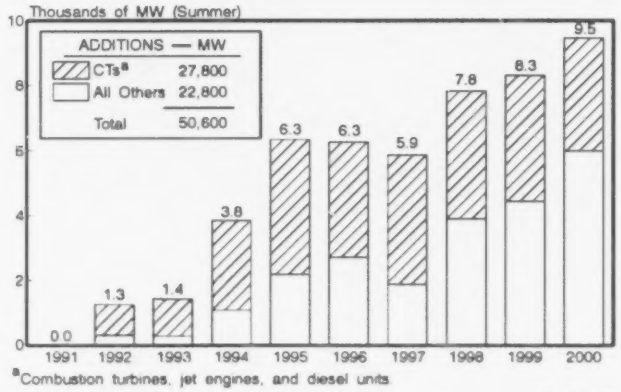


Figure 12

Transmission Reliability Assessment

Transmission systems are expected to be generally adequate throughout the assessment period. Transmission adequacy is measured against electric system, Regional Reliability Council, and NERC planning reliability criteria within the constraints of thermal, voltage, and stability limits. A strong, flexible transmission network is an essential component of a reliable bulk electric system.

Some utilities are concerned that delays in planned transmission additions or mandated use of the transmission systems in ways that were not originally planned could adversely impact reliability. The transmission systems are loaded at or near their capability in some areas. Diminishing transmission capability margins and the decreasing flexibility of these systems to respond to system emergencies are growing concerns.

Some utilities are deferring transmission additions or compensating for transmission delays through the use of complex special protection systems. Others are adding power-flow control devices to minimize the effects of parallel path flows. Guidelines have been developed in several Regions to ensure that these protection systems and devices are reliably planned and operated.

Transmission Reliability

Transmission reliability is the product of careful planning, engineering, operation, and maintenance of the transmission systems. These systems must be able to deliver electricity from generators to major centers of customer demand under a wide range of normal, abnormal, and emergency conditions, and to deliver emergency generation assistance to areas that may be experiencing a temporary deficiency of generating capacity.

Transmission projects require long lead times that extend from the initiation of the planning process, through project authorization, siting and certification including judicial review, engineering and design, right-of-way acquisition, and construction, to the date of commercial operation. The need for transmission facilities must be established many years in advance of the required service date. The determination of need is based upon long-range projections of future customer demands including the effects of conservation and other demand-side management programs, and projections of the size, location, timing, and operational characteristics of new generating units.

Transmission Limits

The ability of the transmission systems to transfer electricity may be limited by any one of three general categories of electric system parameters: thermal limits, voltage limits, and stability limits.

Thermal Limits — Thermal limits are based on the fact that there is a maximum amount of current that a transmission line or electrical device can conduct before it sustains permanent damage.

Voltage Limits — Transmission reliability requires that adequate voltage is maintained throughout the electrical network prior to, during, and after a system disturbance or facility failure. As electric utilities seek to transfer larger amounts of electricity over greater distances and provide transmission service to others, transmission network voltage performance becomes increasingly important. In some Regions, voltage considerations and concerns regarding potential "voltage collapse" represent the prevailing limit to electricity transfers. The result of a voltage collapse is a blackout.

The advance determination, monitoring, and control of system voltages require special attention because system operators may not have sufficient time to avert a voltage collapse once a disturbance has been initiated. In addition, the critical facility failure

Uses of Transmission Systems

Electric transmission systems perform several functions that are vital to the reliability and adequacy of electric supply systems. The major uses of the bulk transmission systems are to:

- ***Deliver electricity to areas of customer demand** — Satisfactory generator sites are often remote from areas of customer demand. Transmission systems are required to provide a reliable network connecting remote generators to customer demand centers.*

- ***Provide flexibility for contingencies** — The interconnected transmission systems provide flexibility to deal with system emergencies and uncertainties, such as outages of generation or transmission equipment, construction delays, higher than expected customer demand, and fuel shortages or disruptions, usually through purchases of electricity from other systems.*

- ***Reduce installed generating capacity** — Transmission interconnections among utility systems allow utilities to share generating capacity through diversity in peak demand and generator availability. Sharing the generating capacity required for adequate reliability significantly reduces each utility's investment in generating facilities.*

- ***Allow sharing of economic generation among systems** — Transmission interconnections among utilities allow use of the most economic generation resources while maintaining reliability. Electric utility customers benefit because the lowest cost generation is dispatched to supply their electricity needs.*

The primary design objective of many interconnected transmission systems was to provide reliability through emergency generation assistance among utilities. In this sense, the transmission system is a resource that provides access to a large source of generating capacity. For example, a large power pool may require a 35% capacity margin if it were not interconnected with other systems. But with sufficient transmission ties to available generating capacity in adjacent large systems, it may only require a 25% capacity margin for the same level of reliability. The capacity value of transmission ties to the large system is ten percentage points in this example. It is important that generation and transmission planners work together to assure proper generation-transmission planning and operating coordination.

In the past, large electricity transfers on the transmission systems were only expected to occur during critical component outages or system emergencies. However, in recent years, these same transmission systems have been routinely used for significant amounts of interregional electricity transfers driven by economics instead of emergency assistance. The transmission systems have performed this economic function well. The increased role of these economic transfers may well influence the need for future transmission additions.

or misoperation that affects voltage stability could be remote from the utility that experiences the largest voltage decrease. As a result, this type of situation is difficult to detect and could go unrecognized until the disturbance occurs. If planning studies detect such a problem, appropriate monitoring, communication, and protection procedures can be developed for use by the operators. Coordination in planning and operating the electric systems is vital to maintaining adequate system reliability, especially when long-distance electricity transfers are common.

Stability Limits — All generators on an alternating current (ac) transmission network operate in synchronism with each other. That is, they operate at precisely the same frequency (60 cycles per second) in lockstep with each other. Immediately following a system disturbance, generators begin to oscillate relative to each other, causing fluctuations in transmission line loadings and system voltages. If the disturbance is minor, the oscillations will diminish as the electric system attains a new, stable operating point. If, on the other hand, the disturbance is severe, the oscillations will increase in magnitude in the seconds following the disturbance. If a new, stable operating point is not quickly established, the generators will fall out of synchronism with one another, and portions or all of the electrical network may become unstable and the result may be system separation, a breakup of the electrical network, or a blackout.

Transmission Assessment

The bulk electric transmission systems as currently planned are expected to be generally adequate during the next ten years. How-

ever, reliability concerns exist in certain areas of ERCOT, MAAC, and MAIN where transmission facilities have not been allowed to be constructed as planned or where the use of the transmission system has changed relative to that for which it was planned.

Electric utilities within each Region continually assess the ability of their transmission systems and interconnections with other systems to meet their individual reliability criteria. These assessments are based on both short- and long-term needs. To complete these evaluations, Regions also participate in joint studies with adjacent Regions. These intraregional and interregional studies measure overall system capability that are used to judge transmission system adequacy.

Planned Additions

The projected transmission circuit mile additions are an indicator of the relative strengthening of the transmission systems. The projected additions in transmission circuit miles by voltage (230 kV and above) are shown in Figure 13 for the United States and Canada over the forecast period. Although the addition of transmission circuit miles indicates a positive reinforcement of the interconnected systems, the increased use of the transmission systems due to customer demand growth, changes in electrical generating capacity, and the increasingly competitive electricity supply market must also be considered in evaluating overall system capability and reliability.

Public Opposition

Within some Regions, public opposition to the construction of new transmission lines is having an adverse effect on electric system reliability. Regulatory pres-

High Voltage AC Electrical Transmission Systems

The high voltage alternating current (ac) transmission systems or electrical networks presently used for the transportation or "transfer" of electricity are fundamentally different from transmission or transportation systems used for the movement of commodities or products of commerce. The reason is that — unlike natural gas or oil in pipes, grain in railroad cars, traffic on the highway — electricity is not readily routed over specific transmission paths on the ac network in place today.

*In gas pipelines, oil pipelines, railroad or highway systems, the "flow" in any segment or along any route can be directly controlled by valves, gates, switches, or traffic lights. However, when a transfer of electricity is made, it generally cannot be directed down specific transmission "paths" or pre-determined routes. Rather, the distribution of electricity flow in each path from generator source to the area of need, or customer demand, is solely a function of the electrical characteristics of the transmission lines and transformers in each path relative to other paths in the network. That is, electricity will use, to varying degrees, **all** available transmission line "paths" between two areas in a system to effect a transfer since electricity follows the immutable laws of physics, rather than human laws or contract paths.*

The loading on a transmission line at a particular instant is not a measure of its use. Most transmission networks are designed and operated on the basis that any one component can fail or be removed from service without causing the remaining facilities in service to be overloaded. For example, if one of two parallel transmission lines is removed from service due to an emergency, the other line must be capable of carrying the resulting power flow — an amount that may approach twice its loading prior to the other line's removal from service.

Because of the number of components and physical size of the interconnected electrical networks, the number of electricity flow patterns possible is essentially infinite. In addition, the configuration of generators and transmission lines changes frequently. These system changes, combined with the instantaneous variations in customer demand and generation dispatch, cause the pattern of electricity flow to change continuously.

As the flow of electricity cannot be made to follow predetermined paths, and as the pattern of flow on the transmission systems or networks is constantly changing, it is not surprising that the capability of these systems to transfer electricity from one point to another is not easily defined. In fact, the capability cannot be specified by a single value. Like the pattern of flow on the network itself, the capability to transfer electricity changes continually.

While "transfer capabilities" between systems are often quoted, it is understood by those who determine them, and those who use them, that these capabilities are approximations corresponding to a specific set of conditions and are not firm values that apply at all times. Therefore, a "transfer capability" should be regarded more as a typical or average value. The actual capability at any moment may be considerably higher or considerably lower.

sure is also influencing electric utilities to provide only the minimum facilities needed in the short term. Comments on the electric and magnetic fields issue and the general opposition to transmission are included in the "Transmission Siting and Services" chapter.

The result of this opposition is a transmission network loaded at or near its capability in some areas, and, therefore, a network that is increasingly sensitive to disturbances or small changes in operating conditions. Because of this trend, owners of transmission are becoming more concerned about their diminishing transmission capability margins and the flexibility of their transmission systems to respond to system emergencies.

Special Protection Systems

In certain instances, utilities have found it appropriate to rely on special protection systems (SPSs) or remedial action schemes in lieu of new transmission lines or where transmission lines have been delayed. SPSs are advantageous in that they are far less costly and are not subject to the environmental concerns associated with siting and building a new transmission line. However, the SPSs must be highly reliable, as the consequences of their failure to operate when called upon could result in widespread interruption of electric service.

Within WSCC, a review procedure has been established to evaluate the design and application of SPSs in an effort to assess the consequences of their failure and minimize their probability of failure. NPCC has also approved guidelines for the application of SPSs. The use of SPSs will continue to be monitored particularly as the reliance upon and the complexity of SPSs continue to increase.

Existing and Planned Transmission

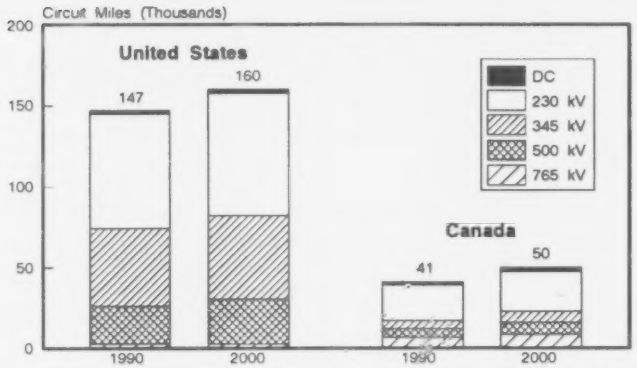


Figure 13

Parallel Path Flow

Because of the nature of ac transmission systems, electricity transfers between two systems can cause flows on parallel transmission paths in other interconnected systems not directly involved in the transfers. Parallel path (or loop) flows are complex network phenomena that affect all utilities, especially those in the general vicinity of significant electricity transfers. These flows make it difficult to analyze system capability and performance because the sources and effects of the multiple transfers are not easily determined. The wide range of electricity transfer possibilities creates a myriad of conditions to study, monitor, and control.

A number of utilities are actively studying parallel path flows in an effort to determine appropriate controls, operating strategies, and/or system-use payments. Some systems are attempting to minimize the effects of parallel path flows and maximize the use of the transmission network by adding power-flow control devices such as phase-shifting transformers, series capacitors, and series reactors. The addition of these devices and their proper operation require close coordination as well as good communications.

Non-Utility Transmission

In a few areas, transmission lines have been built by non-utility generators (NUGs) to deliver their electrical output to the utility systems. To date, most of these non-utility lines are connected radially from the NUG to the utility network, posing no particular problem from a transmission reliability perspective. However, if the non-utility transmission lines are further integrated into the utility network such that they are no longer radial, potential reliability problems can arise if these lines are not planned and operated in compliance with applicable electric system, Regional Reliability Council, and NERC reliability criteria. Close coordination in planning and operating arrangements are required to assure that all transmission, both utility and non-utility, complies with reliability criteria and will not cause adverse safety and reliability effects on overall utility system operations.

Regional Reliability Assessments

The remainder of this report assesses the reliability of the electric generation and transmission systems of the nine Regional Reliability Councils and one Affiliate member, the Alaska Systems Coordinating Council. Some key assessment information for the year 2000 that is discussed in detail in the front portion of the report for the United States and Canada is summarized in the following table for the Regions.

Detailed Regional reliability assessments are discussed in the following ten chapters.

Summary of 2000 Projections for the Regional Reliability Councils

Region	Summer Peak Demand (Thousands of MW)	Annual Net Energy for Load (Millions of MWh)	Summer Generating Capability (Thousands of MW)	Summer Capacity Margin (% Planned Capacity Resources)	Transmission Systems (Circuit Miles in Thousands)
ECAR	92.8	528	109.6	16.0	16.6
ERCOT	52.4	270	61.5	16.7	8.0
MAAC	49.3	270	61.2	24.3	7.1
MAIN	48.0	238	54.5	20.5	5.8
MAPP	34.6	194	41.4	22.9	21.5
NPCC (winter)	118.5	674	145.3	21.2	38.6
SERC	156.4	814	181.6	17.4	30.7
SPP	62.0	303	73.3	17.7	12.2
WSCC	127.5	781	159.9	22.3	69.8
NERC-Total	**722.4**	**4,072**	**884.1**	**21.3**	**210.3**
United States	**651.1**	**3,513**	**774.1**	**19.1**	**159.9**
Canada (winter)	**97.1**	**548**	**110.5**	**14.6**	**49.9**
ASCC (winter)	0.7	4.1	1.3	44.3	0.14

ECAR

East Central Area Reliability Coordination Agreement

The capacity resources planned in ECAR will satisfy the Region's criterion for adequate reliability to serve projected demand and other obligations through the year 2000, provided average generating unit availability can be maintained at or above 76%.

An increase in peak demand growth, a decline in generation availability, or unforeseen impacts of compliance with the U.S. Clean Air Act Amendments of 1990 could quickly reduce system reliability to inadequate levels, possibly requiring installation of additional capacity resources within ECAR.

The transmission network in ECAR is judged to be adequate to handle a wide range of contingencies. However, systems in eastern ECAR will continue to rely on effective operating procedures to control heavy transfer levels to the east and southeast, ensuring reliability on that heavily loaded transmission system interface. Systems on the interface are jointly evaluating additional network reinforcements. Three other major EHV transmission system additions have been announced, which, when completed, will also significantly strengthen the regional transmission network.

Demand and Energy

Throughout the assessment period, ECAR is expected to remain summer peaking, with an equivalent compound growth rate of 1.6% per year for summer and 1.7% for winter peak demands. A comparison of the years common to this year's and last year's (1991-1999) assessment shows that current summer and winter peak demand projections are both about 200 MW (0.2%) higher by 1999. The changes in the summer peak demand projections are illustrated on the forecast comparison figure shown on the following page.

ECAR's annual net energy for load has an equivalent compound growth rate of about 1.7% per year over the assessment period. This year's energy projections are about 1% higher for the years common with last year's projections.

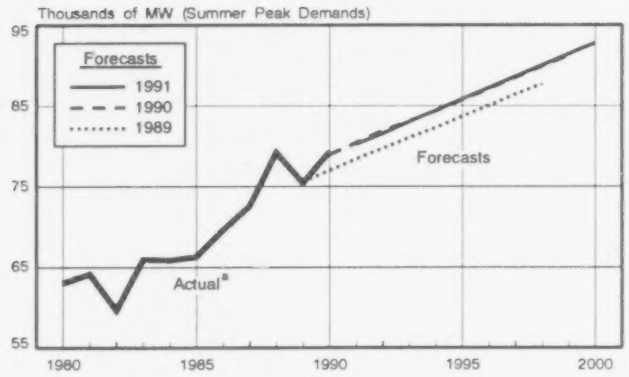
	Year	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Annual Electrical Energy (GWh)	Summer Installed Capability (MW)
Actual	1990	79,258	67,097	442,507	99,480
	1991	80,206	74,981	454,286	101,312
Forecast	2000	92,804	87,268	527,711	109,557
	Growth (%/yr)	1.6	1.7	1.7	0.9

Capacity Resources

ECAR Bulk Power Members plan to add or contract for approximately 9,300 MW of owned or non-utility capacity, return about 2,600 MW to service, retire or deactivate about 2,000 MW, and expect about a 200 MW net capacity increase due to rerating of existing capacity. Reflected in these values is an increase in non-utility generator (NUG) capacity of about 2,100 MW. Some of the planned utility capacity may ultimately be supplied by NUGs or deferred by demand-side management programs.

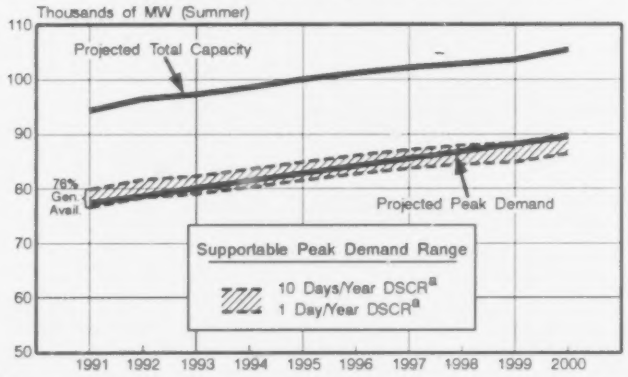
Construction lead time requirements are eight years or more for large baseload coal-fired or nuclear generating units. If the ECAR Region were to experience higher-than-projected demands or unforeseen reductions in existing capacity, it would be very diffi-

ECAR – Recent Forecasts



[a]Not adjusted for weather or operator-controlled demand reductions.

ECAR Bulk Power Members Supply Adequacy Assessment



[a]Dependence on Supplemental Capacity Resources (DSCR) index expressed in days/year.

cult to build new baseload units for service during the ten-year assessment period. Short lead-time capacity, such as combustion turbines or combined cycle units, could be added in time to offset capacity shortfalls. However, uncertainties in natural gas supply and/or fuel oil supply, and site acceptability could adversely impact any short lead-time capacity additions.

An extensive probabilistic adequacy appraisal that considers the combined Regional peak demand pattern and generation availability of the ECAR Bulk Power Members is conducted annually. In that appraisal, ECAR's reliability is evaluated using an index called the Dependence on Supplemental Capacity Resources (DSCR), expressed in days/year. Supplemental capacity resources include assistance from neighboring Regions, dropping contractually interruptible demands, and use of direct-controlled load management. Under severe conditions, emergency operating procedures may call for the interruption of supply to firm customers. Reliability is judged against the ECAR criterion of 1 to 10 days/year DSCR providing marginal but satisfactory reliability.

The availability of generating equipment is one of the most critical parameters to the adequacy of the ECAR bulk electric supply. The ECAR 1991 long-term capacity appraisal determined that the annual generation availability must remain at or above 76% for ECAR to meet its DSCR reliability criterion throughout the assessment period at the projected peak demand annual growth rate of 1.6%. Those results are illustrated on the ECAR " Supply Adequacy Assessment" graph. It was also determined from that appraisal that if the average annual availability declined to 75%, reliability would be inadequate by 1998. For perspective, ECAR's average annual generation availability for non-holiday weekdays has ranged from a low of 76% in 1982 to 81% in 1990, averaging 78% over the ten-year period.

Although high generating unit availability continues to be a primary goal of the systems in ECAR, it may become increasingly difficult to maintain availability at the favorably high levels experienced in recent years, due to such factors as maintenance scheduling problems as margins decrease, the risk of lower availability of aging units, and financial pressures to reduce maintenance expenses.

Aging generating capacity in ECAR carries the risk of decreasing availability. Normal deterioration and obsolescence will necessitate increased maintenance, and component replacements will lengthen outages. Also, should capacity margins decrease as demand grows, it may become very difficult to properly coordinate an adequate planned maintenance program, leading to an increase in random outages. Aging capacity is a serious concern in ECAR because about 38% of the capacity in ECAR will be 30 or more years old by the end of the year 2000, and about 19% will be 40 or more years old.

U.S. Clean Air Act Amendments of 1990

Coal, the predominate fuel used within the ECAR Region, is expected to supply about 87% of the total electrical energy requirements during the assessment period. Therefore, the potential reliability impacts of compliance with the Clean Air Act Amendments of 1990 (CAAA) are of concern in ECAR.

To assess the impact that the legislation could have on ECAR's reliability, a survey was conducted requesting each system in ECAR to provide an estimate of the reliability impacts, i.e., any change in demand forecasts, and unit rating and/or availability. The data provided by the member systems are subject to change since the final U.S. Environmental Protection Agency rules and regulations have yet to be developed.

Unlike previous acid rain analyses, where the compliance impacts were studied as a sensitivity, this year's appraisal directly incorporated the projected impacts due to unit reratings and/or increases in maintenance and random outage factors into the reference case data.

If prolonged retrofitting outages of large generating units are required for compliance with the CAAA, ECAR's coal-fired generating unit availability could be adversely impacted. Such outages will need to be carefully coordinated among the ECAR member systems to maintain the Region's reliability. Another compliance concern is possible delays in the delivery and installation of scrubbers and low-NO_x burners.

The emissions cap provisions of the CAAA may lead to environmental constraints taking precedence over economic dispatch of generation. Should a utility be at or approaching its emissions cap, it may be unable to provide emergency assistance to a neighboring utility without exceeding its cap.

Transmission Adequacy

The ECAR systems have developed an extensive and reliable high voltage and extra high voltage (EHV) transmission network that is interconnected with the networks of neighboring Regions at various voltages. The EHV portion of the network includes over 2,000 miles of 765 kV, about 850 miles of 500 kV, and about 11,800 miles of 345 kV transmission. Current plans call for the addition of about 110 miles of 765 kV, 116 miles of 500 kV, and 445 miles of 345 kV transmission lines between 1991 and 2000. These additions are expected to enhance and strengthen the bulk transmission network.

Included in the above transmission additions are the ECAR portions of the American Electric Power Service Corporation/Virginia Power (765 kV and 500 kV), the Duquesne Light Company/General Public Utilities (500 kV), and the Consumers Power Company/PSI Energy, Inc. (345 kV) transmission projects.

In recent years, fuel cost differentials have fostered large, short-term economy energy transfers, in addition to long-term capacity and energy transfers. Significant intraregional and interregional energy transfers are routinely arranged on daily and hourly bases. These transfers have caused line loading patterns on the transmission systems that were not anticipated when these systems were originally planned. Therefore, the transfers must be carefully monitored and controlled to assure reliable operation of the interconnected systems.

To properly coordinate the planning and operation of the interconnected systems, seasonal transmission performance studies are conducted within ECAR, and jointly with all neighboring Regions, prior to each seasonal peak period. The transmission systems are also regularly analyzed for future periods of interest.

These studies indicate that the bulk transmission systems should perform adequately under a wide range of credible systems conditions. However, portions of the transmission systems in eastern ECAR are expected to be heavily loaded much of the time due to large interregional electricity transfers. A set of operating procedures, called the Reliability Coordination Plan (RCP), was developed by the utilities owning and operating the transmission systems in eastern ECAR, the MAAC Region, and the Virginia-Carolinas (VACAR) Subregion of SERC. The RCP is used to control electricity transfer levels to ensure that reliability is maintained in that heavily loaded part of the transmission network. A number of ECAR systems are participating in interregional studies to evaluate additional reinforcements to increase the transfer capability of that transmission interface. A number of jointly planned shunt capacitor banks are being installed in 1991 and 1992 in eastern ECAR and MAAC to provide additional voltage support. Those installations should improve overall system voltage and reliability during heavy west-to-east electricity transfers.

The East Central Area Reliability Coordination Agreement (ECAR) Region bulk power membership currently consists of 28 companies (19 systems) serving either all or parts of the states of Michigan, Indiana, Kentucky, Ohio, West Virginia, Virginia, Pennsylvania, Maryland, and Tennessee.

ERCOT

Electric Reliability Council of Texas

ERCOT is expected to have adequate capacity margins over the assessment period based on current capacity and demand forecasts. Capacity margins range from 21.7% in 1991 to 15.9% in 1999. Peak demand and annual electrical energy forecasts show slight decreases in growth rate from previous forecasts with the annual growth rate for summer peak demand decreasing from 2.5% to 2.2% and annual energy decreasing from 2.9% to 2.6%. Delays in the addition of needed transmission lines and natural gas supply disruptions are the major concerns for electric system reliability in the Region.

Demand and Energy

The 1990 actual summer peak demand in ERCOT was above the forecast of 41,880 MW by 2% primarily due to warmer than normal temperatures, and above the 1989 actual peak of 40,402 MW by 5.8%. A comparison of recent forecasts of summer peak demand is shown in the figure on the following page.

The average annual growth rate in summer peak demand projected by ERCOT utilities over the 1991-2000 period is 2.2%, a slight decrease from the 2.5% growth rate projected last year. The projected summer peak for 1999, the last year common to both forecasts, is down 1,082 MW or 2.1% from last year's forecast.

Although ERCOT is expected to remain a summer peaking Region, the projected growth rate of the winter peak demands is higher than that of the summer peaks. Two utilities in ERCOT have experienced winter peaks and now project their peak demands to occur in winter due to a high concentration of electric heating in their service areas.

Utility-controlled load management programs, including interruptible demands, are projected to range from 1,349 MW or 3.1% of 1991 summer peak demand to 1,313 MW or 2.5% of the 2000 peak.

Average annual electrical energy growth for the 1991-2000 period is projected to be 2.6%. This is a decrease from last year's forecast of a 2.9% annual increase, largely due to less optimistic projections of economic growth in the Region.

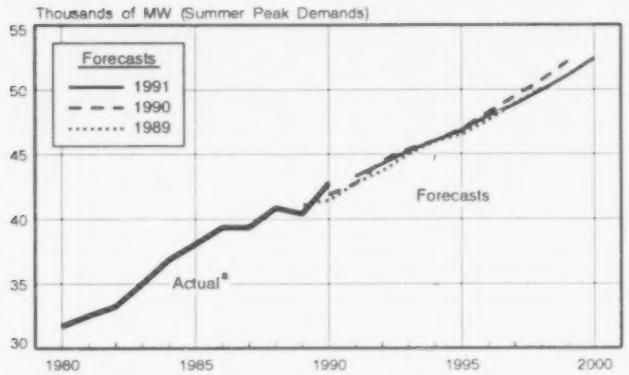
Capacity Resources

The capacity margin in ERCOT is expected to range from a high of 21.7% in 1991 to a low of 15.9% in 1999. Projected capacity margins for the 1991-2000 period are expected to be adequate, exceeding the minimum planning guidelines adopted by the Region. Projected installed generating capacity could support an annual average 2.7% growth in summer peak demand, compared to the 2.2% currently projected, while still meeting minimum ERCOT Planning Criteria. A comparison of ERCOT's planned capacity resources and capacity requirements over the forecast period is shown in the "Supply Adequacy Assessment" figure on the next page.

Utility generating capacity increased by 1,470 MW in 1990. Additional utility generating capacity scheduled for installation between 1991 and 2000 totals 9,902 MW. This includes 4,691 MW of coal capacity, 1,150 MW of nuclear capacity, and 4,061 MW of combustion turbine, combined cycle, and refurbished gas-fired capacity. An additional 1,100 MW of currently unspecified capacity is also projected to be added during the period. Retirements and shutdowns of existing gas-fired units are expected to remove 776 MW of capacity from service during the period. Capacity obtained from non-utility generators is projected to decrease by 2,106 MW. This results in a to-

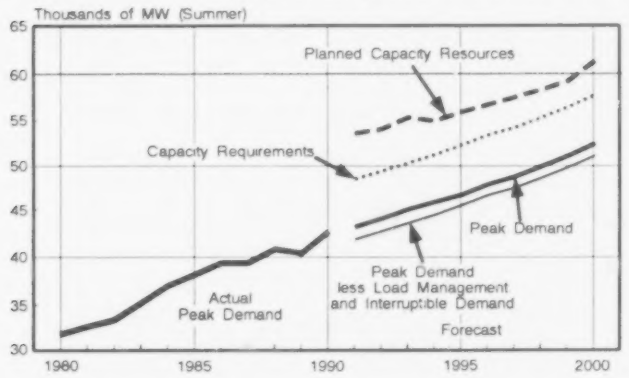
	Year	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Annual Electrical Energy (GWh)	Summer Installed Capability (MW)
Actual	1990	42,737	35,815	209,789	54,114
	1991	43,264	35,718	213,795	54,101
Forecast	2000	52,405	45,386	269,525	61,479
	Growth (%/yr)	2.2	2.7	2.6	1.4

ERCOT — Recent Forecasts



[a]Not adjusted for weather or operator-controlled demand reductions.

ERCOT — Supply Adequacy Assessment



tal net capacity increase in the Region of 8,120 MW.

Non-utility generators (NUGs), which are predominantly gas-fired cogenerators, are projected to account for 3,196 MW or 5.9% of summer generating capacity in 1991 and 1,090 MW or 1.8% of summer capacity in 2000. This decrease in NUG capacity is due to contract expirations. A portion of the 2,106 MW of capacity may continue to be available under future contractual arrangements. The minimum summer capacity margin of 15.9% in 1999 would be reduced to 14.4% without the 1,090 MW of NUG capacity.

The fourth of the Region's four nuclear units, Comanche Peak 2, is scheduled for commercial operation before the 1993 summer peak season.

ERCOT will remain heavily dependent on natural gas-fired capacity throughout the assessment period. ERCOT is expected to depend on utility gas-fired generating capacity for 36.2% of its electrical energy requirements in 1991 and 33.4% in 2000. Electrical energy supplied predominantly by natural gas-fired NUG units will add 5.6% percentage points to the utility gas-fired generation in 2000 for a total of 39%.

Transmission Adequacy

The backbone of the ERCOT bulk electric transmission system is its 6,874 circuit mile 345 kV transmission network. ERCOT members expect to add 1,095 circuit miles of 345 kV lines in the next ten years. This is a 2% decrease from the ten-year projection made in 1990.

A proposed 600 MW East DC Tie to be jointly owned by utilities in ERCOT and the Southwest Power Pool has received approval from the Federal Energy Regulatory Commission. This project will increase the transfer capability between ERCOT and the Southwest Power Pool to approximately 800 MW.

An application for construction of a 345 kV line between Central Power and Light Company's Coleto Creek and Lon Hill power plants has been filed with the Texas Public Utility Commission (PUC). This major transmission project is critical to the reliability of several ERCOT members in South Texas. Approval of the project by the PUC is uncertain since several parties opposing the project have been granted intervenor status in the proceeding.

Studies have shown that the bulk electric systems as planned should meet ERCOT reliability criteria through 2000. However, member utilities continue to have difficulty in obtaining the necessary approvals to construct needed transmission facilities. This uncertainty could pose a threat to electric system reliability in ERCOT.

Operations

Capacity transfers of various types among utilities and from remote NUG units continue to utilize the ERCOT transmission network. In 1990, 1,235 MW of firm capacity from NUGs and 668

MW of firm transfers among utilities were wheeled over the transmission systems. In addition, 2,713 GWh of economy energy transfers occurred among ERCOT utilities in 1990. These uses of the ERCOT transmission network have benefited ERCOT customers by minimizing electricity production costs.

On December 23, 1989 during some of the coldest weather to ever occur in Texas, ERCOT was forced to implement Region-wide firm customer load shedding for the first time in its history. Weather related outages of generating units and high customer demand caused capacity shortages that threatened the stable operation of the interconnected system. Freeze protection on all generating units has been reevaluated and additional protection has been added where necessary. The ERCOT units did not experience any cold weather problems during the 1990/91 winter. However, the weather did not provide as severe a test as December 1989.

Reliability Issues

The major reliability issues of current concern to ERCOT member systems are:

Natural Gas Supply — In 1991, natural gas is expected to provide 46.8% of ERCOT's electrical energy requirements from both utility and non-utility generators. Although the percentage of electricity produced from natural gas will decrease to 39% in 2000, this continued heavy dependence on natural gas causes the availability of natural gas supplies to be a reliability concern.

Gas supplies were abundant throughout most of the 1980s. However, with higher demand for gas, the market has tightened somewhat, especially during the winter seasons. Drilling for gas has increased marginally in recent years, but its level is still well below that of the 1970s. Although additions to gas reserves in the lower-48 states have not declined significantly, most of the reserve additions in recent years have been revisions and adjustments of estimated reserves in previously discovered reservoirs. Uncertainty in the supply outlook and the likely increase in demand for natural gas cause the concern that the availability and deliverability of natural gas may not be sufficient for electrical generation in the future.

U.S. Clean Air Act Amendments of 1990 — Under this program, ERCOT member utilities that need generating capacity can build a new sulfur dioxide emitting generating plant only if they have allowances for the additional emissions. Although a market in which allowances may be bought or sold is expected to develop, it is uncertain what type of market may eventually develop and under what restraints, outside prudency reviews, and costs of transaction. This program will adversely impact the planning and construction of new generating facilities. In addition, the need to continuously track sulfur dioxide emissions from generating units to insure compliance with annual allowance allocations could hinder capacity transfers. Capacity transfers between utilities will, at a minimum, have to take into account both generating costs as well as the value of the allowances used.

Fuel Oil Inventories — To maintain electrical generation during periods of natural gas curtailments, ERCOT member utilities store fuel oil to use as a backup fuel source. Economic and regulatory pressures exist to keep these fuel oil inventories low. The concern in ERCOT is that current inventories may not be sufficient to maintain electric system reliability for an extended period of natural gas curtailments.

Construction of Transmission — It continues to be difficult for ERCOT member utilities to obtain the necessary approvals to construct needed transmission facilities. This comes at a time when the ERCOT transmission network is increasingly used for both firm and economy interchanges.

Questions on the Effects of Electric and Magnetic Fields — One of the issues cited in regulatory and legal proceedings concerning transmission projects is alleged health effects of electric and magnetic fields (EMF). There are also questions as to whether this issue will affect the operation of existing facilities. A special task force appointed by the PUC is scheduled to report on the EMF health effects issue in 1991. This issue could affect the future reliability of the ERCOT system.

The Electric Reliability Council of Texas (ERCOT) is comprised of 23 municipalities, 52 cooperatives, six investor-owned utilities, and two state agencies, which serve a total of 11 million customers. These systems operate 85% of the electric generation in Texas and serve approximately 200,000 square miles or 75% of the area in the state.

MAAC

Mid-Atlantic Area Council

Operating reliability margins have at times over recent years been below desired levels due mainly to the unavailability of large generating units in MAAC and to constraints on the interconnected transmission network. MAAC and adjacent systems are constructing short lead-time transmission enhancements that will improve the overall performance of the transmission network. Once these enhancements are in place, MAAC projects adequate generating capacity and transmission resources throughout the remainder of the 1990s.

Following the completion of the 642 MW Brandon Shores coal-fired unit in 1991, MAAC will rely upon short lead-time resource options to closely tailor its resources to need for the remainder of the decade. If peak demand grows significantly faster than forecast, or if non-utility generator additions or projections of demand-side management effects do not materialize, MAAC may be faced with the need to add increased amounts of short lead-time generating capacity.

Other reliability enhancing measures slated for the 1990s include installation of a fourth 500 kV interconnection with ECAR and completion of the long-delayed Baltimore-Washington 500 kV loop.

Demand and Energy

The 1990 MAAC summer peak demand was 42,613 MW on July 5. Weather conditions on this peak day were quite severe. However, the remainder of the summer season could best be characterized as close to normal.

While the 1990 summer peak was 2.4% greater than the 1989 summer peak, it was 1.2% lower than the all-time MAAC peak demand that occurred in the summer of 1988, and was 122 MW below the 1989 forecast for 1990. Net annual electrical energy for MAAC in 1990 was about 1.3% less than 1989.

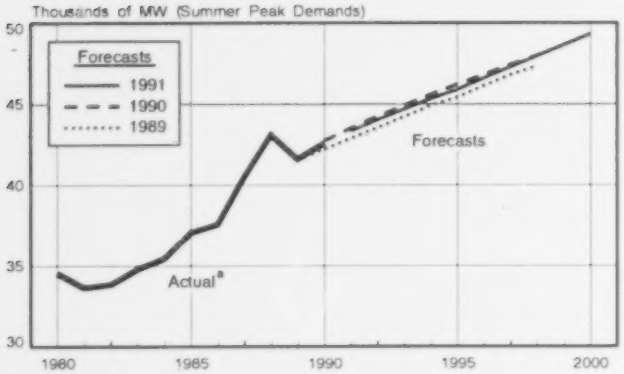
Summer peak demands for the 1991-2000 period are expected to increase 1.4% per year to 49,321 MW by the end of the decade. Growth in annual electrical energy is projected to be 1.9% per year over the forecast period.

The role of demand-side management (DSM) in controlling MAAC's peak demand is projected to increase significantly over the next ten years. In 1991, the estimated peak demand reduction from the effect of DSM is approximately 1,700 MW or about 3.7%. By the year 2000, DSM efforts are projected to reduce peak demands by about 4,000 MW or about 7.5%.

As the amount of DSM increases, and as planned capacity is adjusted downward accordingly, MAAC utilities have become increasingly concerned about the dependence of MAAC reliability on the accuracy of the estimates of future DSM. To deal with this concern, several MAAC initiatives are under way. They include the verification of projected DSM through comparisons with actual experience, and the proper reflection of operational characteristics of specific types of DSM in the determination of the Region's capacity requirements.

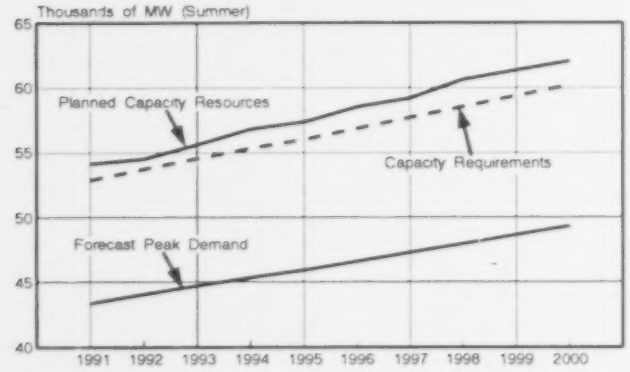
	Year	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Annual Electrical Energy (GWh)	Summer Installed Capability (MW)
Actual	1990	42,613	36,551	221,099	51,279
	1991	43,341	38,481	227,983	53,531
Forecast	2000	49,321	45,492	270,005	61,168
	Growth (%/yr)	1.4	1.9	1.9	1.5

MAAC – Recent Forecasts



[a]Not adjusted for weather or operator-controlled demand reductions

MAAC – Supply Adequacy Assessment



Capacity Resources

MAAC is expected to increase its net installed generating capacity by 9,383 MW over the 1991-2000 period. The new capacity resources include a net increase of 3,439 MW of non-utility generators, and the remainder in short lead-time utility generating capacity, such as oil- or gas-fired combustion turbines and combined cycle units.

Capacity adequacy in MAAC is assessed using loss of load probability (LOLP) analysis. The latest analyses indicate the need for an interconnected capacity margin of about 18% (reserve margin of approximately 22%) to maintain a 0.1 day/year LOLP criteria. Projected capacity margins in MAAC average 20% (25% reserve margin) for the first five years and about 21% (26% reserve margin) for the second five years of the assessment period.

Planned resources in MAAC are adequate to meet projected peak demands throughout the next ten years as illustrated in the figure above. However, if actual growth in peak demand is significantly greater than projected, MAAC utilities may have to implement plans involving additional short lead-time generating capacity. Such action might also be required if some non-utility generator additions do not materialize, or if planned increases in DSM programs fail to produce expected peak demand reductions.

General Public Utilities (GPU) in MAAC is planning to purchase 500 MW of capacity from Duquesne Light Company (Duquesne) in adjacent ECAR beginning in 1994. This transaction includes the renovation of presently inactive coal-fired capacity in Duquesne and a new 500 kV interconnection between the ECAR and MAAC Regions.

In another major initiative to enhance reliability, MAAC utilities have implemented a program of intensified generator unit maintenance. This effort has significantly reduced unplanned unit outages in the last few years.

As a summer peaking Region, MAAC's reliability is adversely affected by generator unit maintenance outages that take place during the summer peak period. Often these outages are extensions of maintenance outages that were scheduled in the spring. MAAC utilities have recently responded to this problem by instituting a system of financial disincentives for peak period maintenance.

Transmission Adequacy

MAAC members plan to install 107 miles of new 500 kV transmission and to participate in another project with a neighboring Region involving approximately 254 miles of additional 500 kV transmission by the year 2000. Also planned by the end of the forecast period is the installation of 390 miles of 230 kV transmission. Major 500 kV developments include the Baltimore-Washington loop now scheduled for completion in 1994, the interconnection between GPU and Duquesne scheduled for 1996,

and the "Alternate Seashore Loop" in New Jersey planned for 1997.

The Baltimore-Washington loop is required to provide adequate interregional electricity transfer capability near MAAC's southern and western interfaces and to provide adequate stability margins in the Baltimore-Washington area. After more than a decade of delay involving siting, certification, and related court actions, the last remaining legal challenge to completion of the project was cleared in 1990. Such open-ended approval and judicial review processes represent a threat to the timely completion of other planned transmission facilities necessary to supply customer demand, particularly in the high growth areas within MAAC.

Reliability of supply in the MAAC Region is dependent, in part, on adequate transmission capability to deliver emergency capacity assistance when extreme weather conditions cause demand to exceed the forecast and/or when multiple outages of critical generating units or other facilities combine to produce a Regional supply deficiency. MAAC plans its transmission network with sufficient emergency import capability to maintain reliability of supply.

Actual system operations in recent years have demonstrated limitations in the capability of the transmission network at the interface between MAAC and the ECAR and SERC Regions. Coordinated interregional studies have developed plans for transmission system enhancements that will ease the transmission bottlenecks. As a result of the first phase of such coordinated studies, MAAC and the Allegheny Power System in ECAR are installing 1,800 megavars (Mvars) of shunt capacitors that will achieve the needed short-term improvements in MAAC's ability to obtain emergency assistance from adjacent systems. By 1996, the GPU/Duquesne 500 kV line is expected to enhance MAAC's reliability by further improving MAAC transmission capability from systems to the west.

Operations

MAAC's electric supply capability as a whole was not seriously challenged during the summer of 1990. However, on July 5, 1990, a combination of high temperatures and the outage of a number of large generating units in the Baltimore-Washington area stressed that area's transmission to its limits. Operators were forced to initiate several emergency procedures culminating in a 5% voltage reduction and manual interruption of customer demands, totaling 400 MW, to maintain system reliability.

This July 5 system condition is not likely to be repeated in the summers ahead due to:

- the return to service of the Calvert Cliffs nuclear units that were unavailable during the summer of 1990,
- the addition to the affected area of Brandon Shores 642 MW unit and the Chalk Point combustion turbines (386 MW) in June 1991,
- the completion of the Baltimore-Washington 500 kV loop scheduled for 1994, and
- facility reconfiguration and installation of a 200 Mvar shunt capacitor at Conastone switching station to relieve voltage constraints at that station.

The interchange of economy energy among MAAC members, economy capacity imports from systems west of MAAC, and unscheduled parallel path flows due to transactions among neighboring systems, all contribute to heavy west-to-east loadings on the MAAC transmission network. These heavy west-to-east transmission loadings are expected to continue in the future, and the voltage constraints that result will continue to be the focus of utility system operator attention.

The combined impacts of transactions of utilities in the MAAC, ECAR, SERC, and NPCC Regions have contributed to voltage limits on the transmission network at the ECAR-SERC-MAAC interface. The Reliability Coordination Plan, jointly developed and implemented by systems within these three Regions, is a cooperative approach to monitoring and controlling the voltage problems in this multiregional area by coordinating the electricity transactions that cause them. As part of an ongoing program of reliability enhancement, the Reliability Coordination Plan was refined during 1990.

Reliability Issues

The planned MAAC system provides adequate future supply for projected conditions. However, several factors could potentially threaten the balance between customer demands and supply resources. Key risk factors include:

Peak Demand Uncertainty — Significant amounts of DSM have been reflected in the projected peak demands. While planned capacity is sufficient to meet peak demand projections (1.4% annual growth), major increases in peak demand growth could trigger the implementation of contingency plans to bring additional capacity resources into service within MAAC.

Emergency Import Capability — MAAC uses its transmission interconnection lines to effect various types of economy and emergency electricity transactions. The recent growth in such transactions has resulted in heavy loadings on the transmission systems in and around MAAC. MAAC and several of its neighboring systems are conducting studies to develop short-term and longer-term transmission reinforcements that will assure desired levels of emergency transfer capability.

MAAC utilities are also concerned about the diminishing prospects for being able to implement needed transmission reinforcements in a timely manner, if at all, given the current environmental climate and lengthy review and approvals processes. Mounting public concern over EMF effects has served to further prolong the review process related to specific planned transmission projects, particularly in New Jersey.

Availability of Generation — Nuclear unit availability in MAAC at time of peak has in recent years been below desired levels, as these units have exhibited vulnerability to extended outages. For example, extended nuclear unit outages were a contributing factor in the July 5, 1990 summer supply problems in southern MAAC. The utilities that operate nuclear units are making every effort to ensure that the highest standards of safety and performance are maintained at these plants, as these large units play a critical role in assuring adequate electric supply.

Fuel Supply Adequacy — The potential for disruption of fuel oil and natural gas supplies poses a threat to the significant portion of MAAC's generating units that rely on these fuels. The growth of non-utility generators, many of which are fueled by natural gas with interruptible gas supply contracts (and many with no alternative fuel supply), heightens this concern.

With increased reliance on natural gas, there are concerns regarding this fuel's deliverability. That is, do natural gas pipelines have adequate capacity to reliably supply electric utility peak requirements during winter cold snaps? There is no assurance that pipeline capacity is designed to comply with electric utility reliability standards.

Clean Air Regulations — Phase I of the U.S. Clean Air Act Amendments of 1990 is expected to have minimal impact on MAAC reliability. Compliance will be achieved mainly through fuel switching or emissions allowance trading. Phase II will probably require scrubber installation on 12 coal-fired units, and possibly as many as 17 units.

The MAAC Region consists of 11 member systems and five associates serving over 20 million people in a 48,700 square mile area. The Region includes all of Delaware and the District of Columbia, major portions of Pennsylvania, New Jersey, and Maryland, and a small portion of Virginia.

MAIN

Mid-America Interconnected Network

MAIN plans to provide adequate generating capacity on a continuing basis. Probability studies show that generation reserve levels will be adequate for the next ten years considering uncertainties due to weather. If demand forecast error is also considered in the probability studies, MAIN may have to add additional resources as early as 1994. Consequently, MAIN is investigating the effectiveness of various strategies to achieve adequate levels of reserve.

A further reliability concern is the unknown effects of the U.S. Clean Air Act Amendments of 1990 on future generating capability.

The transmission network in MAIN is expected to be adequate for reliable operations for both internal transfers and those involving adjoining Regions.

Demand and Energy

The 1990 noncoincident summer peak demand for MAIN was 40,740 MW. This peak is less than the record 1988 peak demand of 41,139 MW. The actual 1990 peak demand was 1,549 MW, or about 4% above forecast. Both actual and weather-corrected peak demands have exceeded forecasts for the past five years.

The MAIN 1990 summer peak demand was reduced 434 MW by removal of contractually interruptible customer demand. No peak reductions through load management programs, voltage reductions, or emergency operating measures were in effect at times of peak demand.

Actual summer peak demands and a comparison of recent forecasts are shown in the figure on the following page. Summer peak demand for the 1991-2000 period is forecast to increase at an average annual rate of 1.7%, the same rate as projected for the last two years. However, as shown in the "Recent Forecasts" figure, the current forecast is about 4% higher than last year's forecast. For example, the present forecast for 1999 summer is 1,760 MW or 3.9% higher than the forecast for 1999 made a year ago.

Actual 1990 electrical energy use in MAIN was 1.2% above forecast. The projected electrical energy average annual growth rate is 1.9%, 0.1% above last year's forecast.

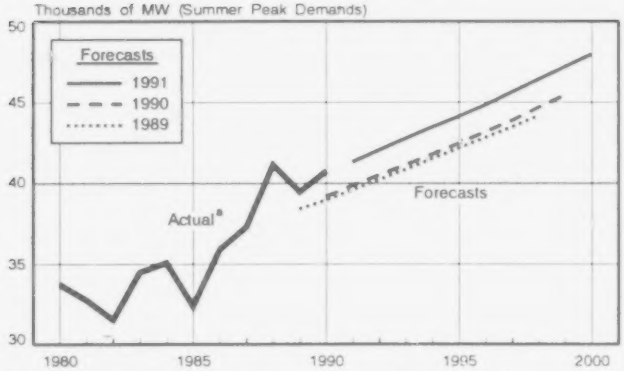
Capacity Resources

The generating reserve policy adopted by MAIN suggests that utilities maintain installed capacity at least 15% to 20% above the forecast peak demand in each year. (This is equivalent to a capacity margin of 13% to 16.8%.) Reserve margins as projected by MAIN are above current minimum requirements throughout the forecast period, ranging from 19.2% in 1991 to 17.2% in 2000, including the effects of load management, interruptible demand, and capacity sales and purchases.

Total summer installed generating capability including non-utility generators (NUGs) is expected to increase by 5,234 MW during the 1991-2000 forecast period, while total internal summer peak demand is projected to increase by 6,653 MW. Considering additional load management and interruptible demands, the net increase in demand is 6,122 MW during this same period, which is about 900 MW above the currently planned capacity increase.

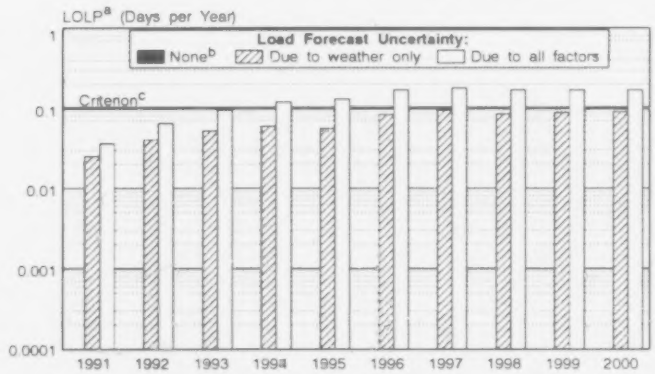
	Year	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Annual Electrical Energy (GWh)	Summer Installed Capability (MW)
Actual	1990	40,740	32,461	197,326	49,184
	1991	41,309	33,668	200,678	49,307
Forecast	2000	47,962	39,923	237,909	54,541
	Growth (%/yr)	1.7	1.9	1.9	1.1

MAIN — Recent Forecasts



[a]Not adjusted for weather or operator-controlled demand reductions.

MAIN — Supply Adequacy Assessment



[a]A Loss of Load Probability (LOLP) of 0.1 day per year is the same as 1 day in 10 years.
[b]Without uncertainty considerations, all LOLP values are less than 0.0001.
[c]MAIN Criterion: LOLP of 0.1 day (or less) per year.

The planned use of NUGs for utility supply in MAIN is relatively small, totaling only 140 MW at time of summer peak in the year 2000. Planned load management increases from 46 MW in 1991 to 293 MW in 2000, and contractually interruptible demand increases from 797 MW in 1991 to 1,081 MW in 2000. These two programs represent 2.9% of MAIN's total internal demand in 2000.

Net summer purchases and sales decrease from net purchases of 483 MW in 1991 to 166 MW in 2000. Of purchases totaling 524 MW in 2000, only 75 MW are from unknown sources.

During the last six years of the forecast period, capacity expected to be inoperable at the time of summer peak is projected to be only 112 MW.

In the past, when generation reserves were ample and electricity could be purchased at essentially the same cost as it could be produced by a unit that was removed from service, MAIN utilities scheduled generator maintenance and nuclear unit refueling at time of summer peak. However, beginning in 1991, no scheduled generator maintenance outages are planned over summer peaks.

In summary, MAIN expects to meet its summer peak demands by adding 5,234 MW of generating capability (including 114 MW of NUGs), by minimizing inoperable capacity, by eliminating scheduled maintenance at time of summer peak, and by increasing contractually interruptible demand and load management.

Supply adequacy in MAIN is assessed using loss of load probability (LOLP) analysis. The adjacent assessment figure shows the latest LOLP analysis, which covers the ten-year period ending in 2000. Considering uncertainties due to weather, and with no more than 1,160 MW emergency imports from neighboring systems, generating capacity will be adequate to meet the MAIN expected LOLP criterion of 0.1 day (or less)/year throughout the ten-year study period. Considering uncertainties due to load forecast error, the study shows that without improved utilization of existing resources or without additional resources MAIN may not be able to meet its LOLP criterion beginning in 1994. Consequently, MAIN is investigating the effectiveness of various strategies to achieve the LOLP criterion of 0.1 day (or less) per year.

Transmission Adequacy

Assuming additional lines can be placed in service as scheduled, the transmission network in MAIN is adequate for reliable operation for both internal electricity transfers and those involving adjoining Regions. Near-term operating studies, longer-term planning studies of interchange capability, and extreme disturbance studies are conducted on a regular basis to assure that transmission capacity will continue to be adequate. Each of these studies includes participation by representatives from adjacent Regions to provide interregional coordination.

Two important transmission lines in MAIN are presently behind schedule:

- The Albion-E. West Frankfort 345 kV line was originally scheduled for completion in 1990. However, due to a lengthy regulatory approvals process, court action required before condemnation, and potential future court actions, the line will probably not be placed in service until 1993. This line will constitute a third 345 kV circuit across southern Illinois and is needed to reinforce the electric supply capability to a large area of southeastern Illinois.

- The Burnham-Taylor 345 kV line was originally scheduled for completion in May 1991. This line, critical to the reliability of service to downtown Chicago, has been delayed at least one year by local permitting problems.

Reliability Issues

Some critical concerns in MAIN that have the potential to adversely impact electric system reliability include:

Clean Air Regulations — Since coal is the major fuel used in MAIN for electricity production, the U.S. Clean Air Act Amendments of 1990 requiring reduced sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions may adversely affect the reliability of supply due to the following:

- Unit capacity may be reduced due to burning low sulfur coal.

- The installation of emissions control equipment often requires lengthy generator unit outages resulting in less capacity to serve customer demand during the periods of retrofitting.

- The maximum net output of most existing high sulfur coal units could be reduced 1.5% to 2% if retrofitted with facilities for SO_2 removal.

- The average availability of retrofitted units may also decrease slightly.

Operation With Lower Margins — Even though minimum reliability criteria will still be met, reliability will be lower than in the recent past as generating reserves decrease from levels well above criteria toward minimum acceptable levels over the next ten years. As utilities operate closer to the lower reserve limits, increased firm purchases and sales of capacity will replace the economy transactions that have predominated in the recent past. Curtailing firm capacity transactions due to transmission emergencies can impact customer reliability far more significantly than the past curtailments of economy energy. With less reserve capability available, flexibility in dealing with emergencies is reduced. In the past, the MAIN systems were capable of surviving multiple contingencies beyond the design level due to greater than planned margins. This capability will be less in the future.

The Mid-America Interconnected Network (MAIN) consists of 14 member systems. MAIN is a summer peaking Region serving a population of 18 million in a geographic area of 170,000 square miles encompassing Illinois, the eastern third of Missouri, the eastern two-thirds of Wisconsin, and most of the upper peninsula of Michigan.

MAPP

Mid-Continent Area Power Pool

The existing and planned generation resources in the MAPP Region are judged to be adequate to supply the projected demand requirements throughout the 1991-2000 assessment period.

The existing and planned transmission network is also judged to be adequate to provide service to the projected peak demands throughout the assessment period.

A near-term reliability concern is continuing drought conditions in the Region. MAPP's hydroelectric generating capacity supplied 21% of the total electrical energy produced by the Region in 1990. Continuation of the drought could limit the electrical energy production of this resource.

In the longer term, a higher than projected peak demand could cause some reliability concerns near the end of the forecast period. Experience with load management continues to reinforce confidence in this strategy as a means of minimizing future capacity additions.

Demand and Energy

The MAPP Region in total matched its forecast for 1990 summer. The utilities in the U.S. portion of the MAPP Region established record summer peak demands that were 1% above those forecast in 1989 for 1990. The utilities in the MAPP-Canada portion of the Region experienced winter peak demands equal to those forecast in 1989 for the 1990/91 winter.

MAPP-U.S. is projecting slightly lower annual growth in summer peak demands, higher growth in annual net energy for load, and the same annual growth in winter peak demands as last year. The projected 1999 summer peak demand of 28,373 MW is essentially the same as projected last year for 1999. MAPP-Canada is projecting annual growth in summer peak demands and annual net energy for load somewhat greater than in 1990, but projected annual growth of winter peak demand is the same.

Actual peak demands and ten-year projections made in 1989, 1990 and 1991 are shown in the figure on the following page.

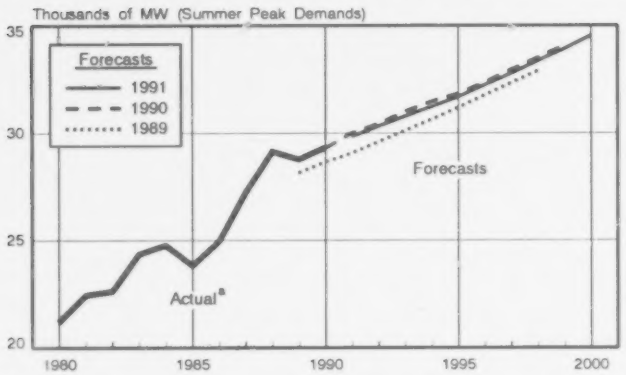
MAPP utilities continue to actively pursue demand-side management activities, such as conservation, load management, and interruptible demands. Many of the effects of these programs are reflected in the projected peak demands and annual net energy for load.

Capacity Resources

The planned capacity resources throughout the assessment period are judged to be adequate for the projected peak demands. The MAPP-U.S. utilities are projecting capacity margins from 25% in 1991 declining to 22.7% in 2000 at the time of summer peak demand. The MAPP-Canada utilities are projecting capacity margins from 25.6% in 1991/92 declining to 14.6% in the 2000/01 winter season. These capacity margins are based on load management and interruptible demand options being exercised. Projected peak demands, planned ca-

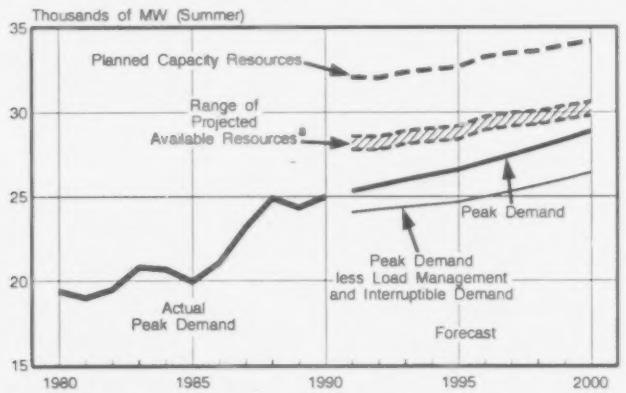
	Year	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Annual Electrical Energy (GWh)	Summer Installed Capability (MW)
Actual	1990	29,323	27,043	157,702	39,196
	1991	29,833	27,595	161,510	38,949
Forecast	2000	34,551	32,499	194,467	41,437
	Growth (%/yr)	1.6	1.8	2.1	0.7

MAPP – Recent Forecasts



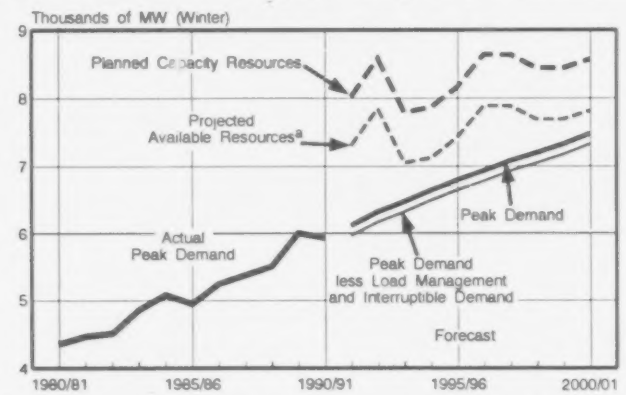
[a]Not adjusted for weather or operator-controlled demand reductions.

MAPP-U.S. – Supply Adequacy Assessment



[a]Projected Available Resources are equal to Planned Capacity Resources less spinning reserve requirements and projected unavailable capacity at the time of system peak.

MAPP-Canada – Supply Adequacy Assessment



[a]Projected Available Resources are equal to Planned Capacity Resources less spinning reserve requirements and projected unavailable capacity at the time of system peak.

pacity resources, and projected available resources at the time of system peak demand are shown for MAPP-U.S. and MAPP-Canada in the adjacent figures. These figures illustrate the adequacy of the Region's generation capacity to meet projected peak demands. Required capacity resources are determined through analytical methods to meet the Region's reliability criteria.

MAPP-U.S. and MAPP-Canada depend primarily on nuclear, coal, and hydro for electrical energy production. In 1990, 15% of the total electrical energy produced was by nuclear generation, 64% by coal, and 21% by hydro. Less than 1% of the annual electrical energy was produced by oil or gas. This mix of energy production is projected to remain essentially the same throughout the assessment period. Non-utility generators represent only 1% of the capacity resources in MAPP and provide minimal electrical energy production.

The only major power plants under construction are the 1,300 MW hydroelectric plant in Manitoba with completion in 1992, and a 280 MW lignite-fired unit in Saskatchewan scheduled for service by the summer of 1992.

The utilities are planning to meet future peak demand growth that isn't covered by load management through improved availability of existing generating units and the addition of peaking capacity, with over 1,100 MW of combustion turbines and combined cycle units being proposed. No new coal-fired generators are being proposed in MAPP-U.S. during the 1991-2000 period. A 270 MW lignite-fired unit is proposed in Saskatchewan in 1996, and the first two 130 MW units of a 1,300 MW hydroelectric plant are proposed in Manitoba for service in 2000.

Transmission Adequacy

Existing and projected transmission facilities are judged to be adequate to supply the projected peak demands in the Region through the ten-year assessment period.

The MAPP utilities have 19,322 miles of ac and dc transmission lines, 230 kV through 500 kV, in service. Over the next ten years, plans call for the construction of an additional 2,179 miles of transmission lines, 230 kV and above.

These transmission additions include two additional MAPP to NPCC interconnections. A new 500 kV interconnection between Manitoba and Ontario is planned for 1999, and a new 115 kV interconnection between Minnesota and Ontario is proposed for 1993. The Manitoba interconnection will include a 1,000 MW long-term capacity sale from Manitoba Hydro to Ontario Hydro. These additions also include a new 345 kV interconnection between MAPP and SPP in 1992 that is expected to increase transfer capability between the two Regions by approximately 1,000 MW. The existing transmission facilities interconnecting Manitoba to the United States are being increased by 400 MW of capacity.

Operations

MAPP has instituted a loss repayment procedure to compensate third parties for losses they incur due to transactions among MAPP members. MAPP has a policy to encourage transactions among its members to maximize efficiency and minimize costs without adversely affecting any other member. During 1990, over 27% of the total MAPP net energy for load was supplied through purchases from another utility within MAPP or from neighboring systems.

Reliability Issues

The major reliability issues in the MAPP Region are peak demand uncertainty, fuel supply uncertainty, transmission systems use, and electric and magnetic fields regulations.

Peak Demand Uncertainty — As peak demands continue to grow, capacity margins become minimal toward the end of the forecast period. The possibility of actual peak demands exceeding forecast causes concern about the adequacy of generation supply.

Fuel Supply Uncertainty — Although the MAPP utilities do not depend on fuel oil or natural gas for any significant amount of electricity production, they do have 11% of their electric generating capacity dependent on oil and gas availability. Of greater concern is the drought situation. The MAPP Region has 20% of its generating capacity in hydroelectric plants, which in 1990 produced 21% of the total electrical energy production in the Region. The continuing drought in the U.S. portion of MAPP threatens the reliability of this resource. In addition, the majority of the Region's large coal and nuclear plants are dependent on adequate river flows to provide cooling.

Transmission Systems Use — Increased use of the existing transmission systems to provide firm capacity from remote generating units is increasing the committed loading on the transmission network thereby reducing reliability margins.

Electric and Magnetic Fields Regulations — The present concern about possible adverse health effects of electric and magnetic fields could lead to regulations potentially affecting the operation of MAPP's existing and planned transmission network.

The Mid-Continent Area Power Pool (MAPP) membership includes 45 systems. The 28 participants consist of 11 investor-owned systems, eight generation and transmission cooperatives, three public power districts, five municipal systems, and one federal agency. The associate participants consist of two Canadian Crown Corporations, 13 municipals, one municipal agency, and one investor-owned system. The MAPP Region covers all or portions of the states of Iowa, Minnesota, Nebraska, North Dakota, Illinois, Michigan, Montana, South Dakota, and Wisconsin; and the provinces of Manitoba and Saskatchewan. Total geographic area served is 890,000 square miles with a population of 16 million.

NPCC

Northeast Power Coordinating Council

NPCC member systems are planning for adequate resources into the future through the use of a variety of demand-side and supply-side resource options. Significant amounts of non-utility generators and demand-side management have been included in the projected resources, especially in New York, New England, and Ontario. The dependability of these options on a long-term basis and their availability during peak demand periods are reliability concerns.

Reliability of the transmission network depends on the timely completion of planned reinforcements, the location of non-utility generators, and continued coordination in operations.

Demand and Energy

For the U.S. members of NPCC, the summer peak demand in 1990 was 2% below the 1989 level and about 6.1% below the projected value made just one year earlier. Annual electrical energy in 1990 declined by 1.3% from 1989 and was 2.6% under forecast. Milder than normal weather, the economic recession, and greater than anticipated conservation contributed to these reductions.

For the Canadian members of NPCC, the 1990/91 winter peak was about 1% above the previous winter's peak, but about 5.4% below forecast. The 1990 summer peak was almost exactly on forecast. Annual electrical energy declined by 2.3% from the previous year and was 2.8% below forecast.

Comparisons of actual peak demands for NPCC-U.S. and NPCC-Canada and the forecasts made in 1988, 1989, 1990, and 1991 are shown in the figures on the following page.

The current forecast for NPCC-U.S. for the 1999 summer peak demand, the last common year of the ten-year forecasts, is approximately 7,000 MW or 12.4% lower than last year's forecast for 1999. This decrease is attributable to lower economic projections, increased conservation efforts, and changes by both New York and New England in their reporting practices concerning the different types of demand-side management (DSM) programs.

The current winter peak demand forecast for NPCC-Canada is virtually unchanged from last year's forecast.

Resource Adequacy

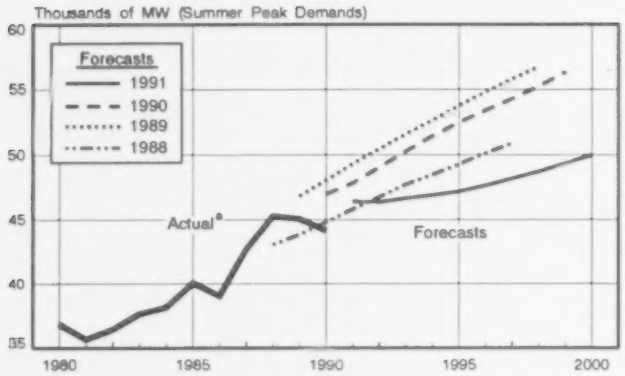
The planned resources in each of the NPCC Areas are adequate throughout the next ten years. This assumes that utility capacity plans, non-utility generator (NUG) projections, anticipated purchases, and DSM programs will be realized as scheduled. It also assumes that the actual peak demand will not significantly exceed current forecasts.

The utilities in New York have strengthened their commitment to DSM over the past year and are now projecting that DSM programs will reduce New York's peak load by 2,660 MW by the year 2000. Planned capacity resources include 4,580 MW of negotiated contracts with NUGs (including 960 MW from a competitive bidding process), and 385 MW of utility hydro additions.

New York's firm transactions with Hydro-Québec include a winter sale of 400 MW to Hydro-Québec and a 500 MW purchase from Hydro-Québec commencing in the summer of 1995 and increasing to 1,000 MW in the summer of 1996 for the remainder of the forecast period. The existing

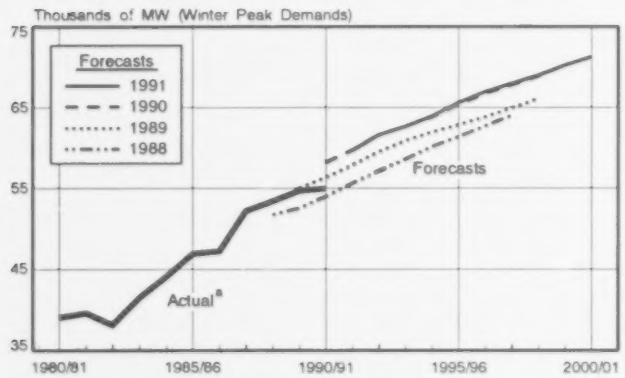
	Year	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Annual Electrical Energy (GWh)	Winter Installed Capability (MW)
Actual	1990	84,023	95,577	552,234	120,309
	1991	87,653	102,915	576,460	125,237
Forecast	2000	99,269	118,514	673,655	145,340
	Growth (%/yr)	1.4	1.6	1.7	1.7

NPCC-U.S. – Recent Forecasts



[a]Not adjusted for weather or operator-controlled demand reductions.

NPCC-Canada – Recent Forecasts



[a]Not adjusted for weather or operator-controlled demand reductions.

800 MW summer purchase from Hydro-Québec will continue throughout the assessment period.

In New England, the commissioning of the Seabrook nuclear plant (1,150 MW) and the energization of the Hydro-Québec Phase II high voltage, direct current interconnection during 1990 significantly enhanced the near-term supply-side picture. Planned resources include approximately 700 MW of NUG additions and a total of about 2,000 MW of DSM and NUGs netted from peak demand by the end of the forecast period. In addition, NEPOOL has identified through the year 2000 a total of approximately 5,800 MW of proposed and contingency resources.

In Ontario, resource additions projected as a part of Ontario Hydro's comprehensive 25-year demand/supply resource plan include: three additional 881 MW nuclear units at the Darlington generating station, about 1,430 MW of hydro capacity, and about 1,600 MW of NUGs. DSM initiatives are estimated to reduce peak demand by 3,200 MW by the end of the forecast period. In addition, the status of some 1,550 MW of mothballed capacity is reviewed periodically depending on demand growth, purchases, and generation availability.

Hydro-Québec's hydroelectric reserve situation, which has been seriously affected by drought conditions over the last five years, has improved. This improvement is due mainly to higher (near normal) annual natural inflows as compared to those of last year.

Because of additional electrical energy requirements, Hydro-Québec has advanced to 1993 the commissioning of two of the six generating units at the Laforge 1 generating station and both units at the Laforge 2 generating station to 1995. Total planned resource additions for Hydro-Québec include: about 10,400 MW of utility hydro capacity, 1,050 MW of utility combustion turbines, about 390 MW of NUGs, and 350 MW of interruptible demand.

Planned capacity resource additions in the Maritimes, which total about 2,000 MW, include a 165 MW circulating fluidized bed combustion generator in Nova Scotia and a 450 MW coal unit equipped with scrubbers in New Brunswick. In addition, 300 MW of existing generation in New Brunswick will be retrofitted with scrubbers and converted to burn an emulsion of natural bitumen and water. DSM initiatives in the Area are expected to reduce forecast peak demand by 300 MW.

The figures on the following page provide an overall adequacy assessment of the planned capacity resources for NPCC-U.S. (summer) and NPCC-Canada (winter). The required capacity resources for each NPCC Area were calculated individually utilizing probabilistic techniques employed by each Area and were then totalled for comparison with the planned capacity resources.

Transmission Adequacy

The existing New England, New York, Ontario, and New Brunswick interconnected bulk

electric transmission systems meet NPCC Criteria, and are expected to continue to do so throughout the forecast period.

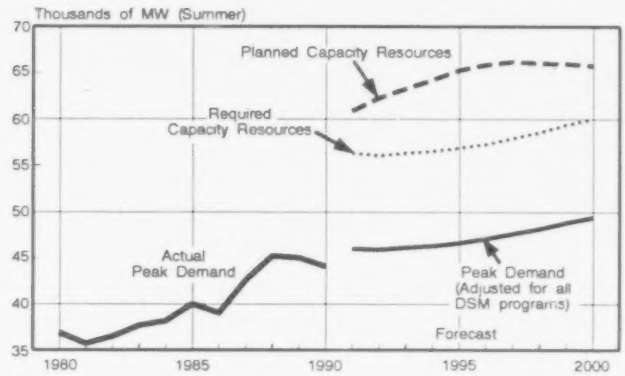
Hydro-Québec and Nova Scotia Power Corporation joined NPCC with the understanding that, although their systems did not satisfy all of the provisions of the NPCC Criteria, contingencies on their systems would not be allowed to have a significant adverse impact on the other NPCC systems. Both the Hydro-Québec and Nova Scotia systems are operated within this constraint.

More recently, following a thorough assessment, NPCC has endorsed a Hydro-Québec system enhancement plan to bring Hydro-Québec's bulk electric system into full conformance with NPCC planning and operating criteria. This reinforcement plan involves the installation of over 13,000 megavars of series compensation on the Hydro-Québec 735 kV transmission system. Static var compensators, shunt reactors, and special protection systems also are included. The plan is scheduled to be fully implemented by 1996.

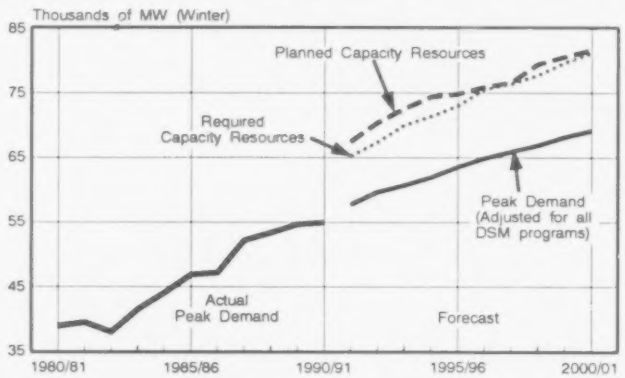
In the Canadian Areas of NPCC, planned transmission line additions during the ten-year forecast period for voltage levels 230 kV and above total approximately 6,100 miles. Included in this total is a 500 kV interconnection between Ontario Hydro and Manitoba Hydro, which is planned for 1999. In addition, a 115 kV interconnection between Ontario and Minnesota has been proposed for 1993.

By contrast, in the U.S. Areas of NPCC, planned transmission additions total about 290 miles. This lack of construction of new transmission in NPCC-U.S. means that portions of the existing New York and New England transmission systems could experience increased loadings as peak demands grow.

NPCC-U.S. – Supply Adequacy Assessment



NPCC-Canada – Supply Adequacy Assessment



On Long Island, a new transmission interconnection from the upstate New York 345 kV network to the Hempstead area was energized in May 1991. This new interconnection will result in significantly improved reliability for Long Island and allow an increase in the economic displacement of oil-fired generating capacity.

Operations

Coordination in operations within NPCC is achieved through a hierarchical system. Criteria, guides, and procedures developed at the NPCC level are expanded and implemented at the Area level by the two U.S. power pools and four Canadian member systems. Each of the U.S. pools and Canadian systems operates a centralized control center for economic dispatch, overall system monitoring, and control.

In New England, control proceeds from the New England Power Exchange (NEPEX) dispatch center to satellite centers and then to individual utilities. In New York, control proceeds from the New York Power Pool (NYPP) dispatch center to the utilities. Telecommunication systems and computer networks link NEPEX, NYPP, and the Canadian

control centers with each other and with neighboring systems in other Regions.

In recent years, intraregional and interregional communications have been increased. Through a "Procedure for Special Communications," weekly updates of interpool reserve margins are exchanged and conference calls are held among system operators in anticipation of emergency conditions.

In addition, NPCC has implemented "Procedures for Solar Magnetic Disturbances on Electrical Power Systems" through which NPCC Areas receive solar magnetic disturbance forecasts and alerts. On receiving notification of a significant solar magnetic disturbance, existing and planned operations are reviewed for vulnerability to such storms.

Interpool coordination agreements exist among the NPCC Areas and with neighboring systems. Further, NPCC is a party to Inter-Area Coordination Agreements with MAAC and ECAR. Through these and a similar agreement among MAAC, ECAR, and the Virginia-Carolinas (VACAR) Subregion of SERC, studies are regularly conducted among MAAC, ECAR, and NPCC (MEN) and VACAR, ECAR, and MAAC (VEM). All are performed under the auspices of a permanent Joint Interregional Review Committee made up of representatives from ECAR, MAAC, NPCC, and VACAR.

Reliability Issues

Substantial increases in the use of natural gas for electricity generation can be expected in NPCC during the 1990s. This increased use can be attributed to the conversion of oil-fired generating capacity to dual-fired capacity, responses to environmental regulations, and non-utility generation. It is estimated that electrical energy from NUGs will triple from 1991 to 1995, with 70% of this NUG capacity expected to be supplied by natural gas. However, there are concerns regarding the future availability and deliverability of large amounts of natural gas to the Northeast. Of particular concern are the reliability impacts of a sudden gas supply interruption and the ability of the gas supply system to respond to transient conditions, such as the daily ramping of gas-fired electrical generators.

A significant amount of NUG capacity and DSM has been included in the projected NPCC resources for the next ten years, especially in New York, New England, and Ontario. However, there is uncertainty regarding these projections. Future NUG additions depend on the long-term availability and deliverability of natural gas, the ability to obtain building permits, and meeting environmental regulations. Future DSM additions will depend on the cost effectiveness of these programs.

New York and New England utilities are currently reviewing the U.S. Clean Air Act Amendments of 1990 (CAAA) to develop strategies to comply with specific requirements. The degree to which this legislation will impact reliability depends on how the regulations implementing the law will be finalized by the U.S. Environmental Protection Agency. In general, compliance will require increased use of lower sulfur fuels and natural gas. Existing power plants were designed to operate with fuels having very specific characteristics. Switching to different fuels may cause operating problems, including unit derating, which could impact system reliability.

As an example, Ontario Hydro, now in its fifth year of major air emissions reduction, has experienced operating problems and severe unit deratings as a result of switching to lower sulfur coal, despite the addition of flue gas conditioning facilities.

In addition, certain states may establish environmental regulations more stringent than that required by the CAAA. New York State is presently drafting regulations to reduce emissions of greenhouse gases, particularly carbon dioxide. As presently drafted, these regulations would require the retirement or repowering of several fossil-fired units.

The Northeast Power Coordinating Council (NPCC) represents 23 investor and publicly-owned utilities serving about 44 million people in a one million square mile area encompassing the northeastern United States and eastern Canada. In the United States, NPCC members participate in either the New England Power Pool (NEPOOL) or the New York Power Pool (NYPP), which constitute two of NPCC's five Areas. In Canada, Ontario Hydro, Hydro-Québec, New Brunswick Power, and Nova Scotia Power are province-wide systems and make up three of NPCC's Areas — Ontario, Québec, and the Maritimes.

SERC

Southeastern Electric Reliability Council

Planned capacity resources are judged to be adequate to supply the projected annual summer peak demand growth of 2.5%. Nearly 38% of the planned capacity additions in the next ten years will be combustion turbine and combined cycle units. Approximately 6,553 MW of operator-controlled load management and interruptible demand, representing 4.2% of peak demand, are planned to be available by the year 2000. The main reliability concern is that a large number of modifications are required on coal-fired generating plants in a short time frame to comply with clean air legislation. This activity could cause reduced availability of generating units during that period.

The transmission systems within SERC are expected to meet SERC reliability criteria during the assessment period. Studies indicate that the transmission systems are capable of supplying contractually scheduled capacity transfers and emergency transfers among the SERC subregions and between SERC and other interconnected Regions. However, the increasing use of the transmission systems for scheduled transactions has resulted in heavy loadings on critical lines in some areas of SERC and has limited interregional economy transfer capability.

Demand and Energy

The 1990 summer peak demand of 121,149 MW was a 3.5% increase over the 1989 summer peak, but was 0.4% below forecast. The 1991-2000 forecast of average annual growth in summer peak demand has decreased from last year's 2.7% to 2.5%. The summer peak demand projected for 1999 (the last common year of the last two forecasts) is 1,704 MW lower than projected last year.

SERC member systems are aggressively pursuing load management and interruptible demand programs. These programs are expected to increase from 3,727 MW or 3% of the 1991 peak to 6,553 MW or 4.2% of the 2000 peak. These programs for 1999 are 938 MW higher than projected last year. Successful implementation of planned load management programs will be important to the reliability of the SERC systems.

Annual electrical energy increased by only 0.7% in 1990 and was 2.2% below forecast, reflecting the unusually mild weather during the year. The projected average annual energy growth rate for the 1991-2000 period is 2.4%. This rate is a decrease from last year's projected growth rate of 2.6%, and is due mainly to lower economic growth projections and increased conservation activities.

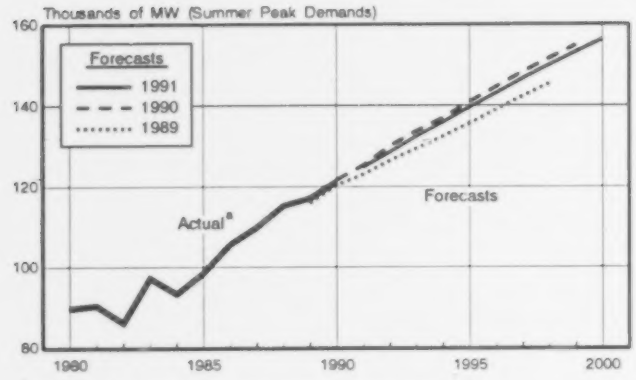
Capacity Resources

Planned capacity resources in SERC are judged to be adequate during the review period to supply projected customer demands. Planned capacity margins are nearly constant (at about 17%) throughout the planning period.

Because of system demand characteristics and the existing capacity resource mix, many sys-

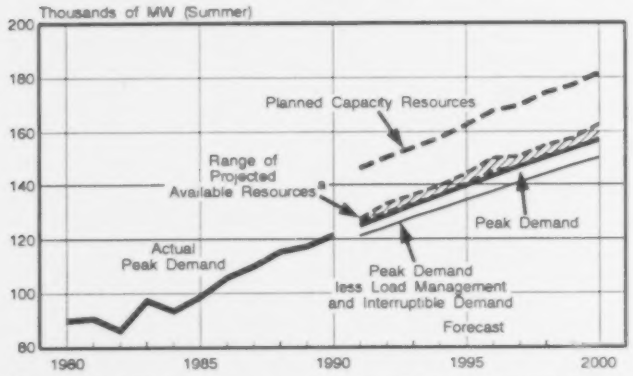
	Year	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Annual Electrical Energy (GWh)	Summer Installed Capability (MW)
Actual	1990	121,149	117,231	627,707	144,281
	1991	124,782	122,616	654,690	146,933
Forecast	2000	156,442	151,927	813,862	181,591
	Growth (%yr)	2.5	2.4	2.4	2.4

SERC – Recent Forecasts



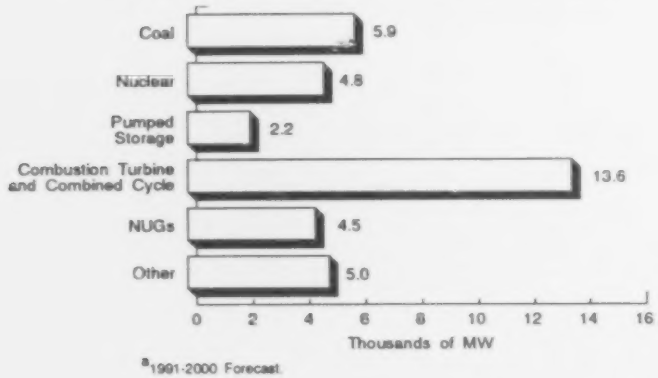
[a]Not adjusted for weather or operator-controlled demand reductions.

SERC – Supply Adequacy Assessment



[a]Projected Available Resources are equal to Planned Capacity Resources less spinning reserve requirements and projected unavailable capacity at the time of system peak.

SERC Planned Capacity Additions[a]



[a]1991-2000 Forecast.

tems are planning combustion turbine and combined cycle capacity additions. Regulatory and financial factors have also influenced capacity planning. For example, Georgia Power Company has announced its intent to sell its Scherer No. 4 unit (848 MW) to Florida Power & Light Company and Jacksonville Electric Authority. This coal-fired unit was completed in early 1989 but had not been allowed in Georgia Power's rate base.

Non-utility generators (NUGs) will increase significantly in the Florida Subregion and portions of the Virginia-Carolinas (VACAR) Subregion. Experience indicates that not all proposed and/or contracted NUGs will be available as scheduled. Thus, some systems are applying attrition factors to account for this probability of installation. Contractual provisions are being negotiated to ensure the long-term and high availability of NUG capacity during peak demand periods and to ensure the proper integration of NUG capacity into the transmission network to prevent degradation of electric system reliability.

Net capacity additions within SERC for the 1991-2000 period total about 36,000 MW as shown in the adjacent figure. Some additional capacity resources are presently in the early planning stages. Therefore, current projections do not include the total amount of capacity that will be added. The additional units are expected to come on line in the latter half of this review period.

Transmission Adequacy

SERC systems have coordinated transmission planning and operations to assure the continued use and expansion of a reliable transmission network. SERC is directly interconnected with the transmission systems in four other

Regions (SPP, MAIN, ECAR, and MAAC), and SERC members actively participate in inter- and intraregional transmission studies. Near-term operating studies and longer-range planning studies are made on a regular basis to ensure that transmission capacity will be adequate. These studies include representatives from each of the SERC subregions and from adjacent Regions to provide interregional coordination. Results of these studies indicate that existing facilities, along with those planned to meet the future reliability needs of the SERC subregions, will provide adequate normal and emergency transfer capability between SERC and other Regions and among the SERC subregions. All systems within SERC expect to meet SERC reliability criteria during the review period.

Due to limitations on existing transmission systems at the ECAR, MAAC, and SERC transmission interface, economic capacity transactions must be curtailed or constrained at times to prevent voltage reductions below defined acceptable limits or line loadings exceeding thermal limits. A number of joint studies have been undertaken to identify methods of strengthening this interface. As a result of these studies, Virginia Power (SERC) and American Electric Power Service Corporation (ECAR) have reached agreement in principle on a major transmission improvement that includes approximately 102 miles of 500 kV and about 110 miles of 765 kV transmission. The necessary permitting, route investigation, and detailed engineering activities for this improvement have begun. Completion is scheduled for 1998.

Florida Power Corporation (FPC), Florida Power & Light Company (FP&L), and the Southern Company are in negotiation to provide additional 500 kV transmission facilities to improve reliability during peak demand periods, increase economic transactions, and offset generation construction. The proposed construction will include new 500 kV transmission lines from the Southern systems to Central Florida substation near Leesburg, Florida and from Kathleen substation near Lakeland to Orange River substation near Ft. Myers. There will be connections into the existing network at several points. This 500 kV project increases import capability by 1,300 MW and is scheduled for completion in 1997. FPC and FP&L will be responsible for building the lines within their service areas and will receive a proportionate share of the 1,300 MW benefit.

The existing SERC transmission systems include 19,911 miles of 230 kV and 7,614 miles of 500 kV transmission lines. Approximately 2,073 miles of 230 kV and 1,100 miles of 500 kV lines are expected to be added in the 1991-2000 period.

Operations

Heavy loadings at the ECAR-SERC (VACAR)-MAAC interface continue due to large west-to-east electricity transactions. Affected utilities have implemented the Reliability Coordination Plan (RCP), which is a cooperative approach to monitoring and controlling power flows in the area. The RCP insures that adequate voltage is maintained and provides a means for reducing transmission loadings on an equitable basis when necessary.

U.S. Clean Air Act Amendments of 1990

The SERC Region depends on coal for 58% of its electrical energy requirements. As a result, the Region will be significantly affected by the U.S. Clean Air Act Amendments of 1990 (CAAA).

The main impact of Phase I of CAAA will be on the Southern and TVA Subregions. These subregions have approximately 10,500 MW and 7,000 MW of generating capacity, respectively, affected by Phase I. Low NO_x burners will have to be installed on this capacity. In addition, switching to low sulfur coal or the installation of scrubbers will be required to meet sulfur dioxide limits. The main reliability concern is that with so many modifications being required in a relatively short period of time, unit availability could be reduced by increased planned and/or forced outages.

It is difficult to assess the CAAA Phase II impacts as most systems have not yet developed their compliance strategies.

Florida Subregion

The Florida Subregion is winter peaking and is comprised of 57 electric utilities operating 19 control areas. The Florida Electric Power Coordinating Group's (FCG) System Planning Committee conducts the necessary studies to determine the adequacy and reliability of Florida's bulk electric supply. The FCG coordinates its planning with the Southern Subregion via the Southern/FCG Reliability Coordination Agreement and the Southern/FCG Planning Task Force. Based on internal and joint studies, the Florida Subregion is expected to meet or exceed the requirements of SERC Guideline 3, Criteria for Reliability in System Planning. Planned generating capacity resources are adequate to supply projected demands. However, capacity margins, ranging between 12% and

14.6% over the assessment period, will be tight during winter peak periods.

The severe cold in December 1989 forced Florida utilities to interrupt service to over one million customers. During 1990, the FCG in conjunction with the Florida Public Service Commission, the Governor's Energy Office, the Division of Emergency Management, and the Office of the Governor developed the Florida Electric Emergency Contingency Plan-Generation Capacity Shortage Element. The plan provides for early identification of situations that could lead to electricity shortages, coordinates actions among utilities, regulators, legislators, and state and local emergency agencies, and establishes a communications network to assist customers during generating capacity shortages.

Southern Subregion

The Southern Subregion is comprised of the following systems: Alabama Electric Cooperative, Crisp County Power Commission, Southeastern Power Administration, South Mississippi Electric Power Association, and the Southern Electric Systems consisting of Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric & Power Company. The Southern system companies comprise the majority of the subregion's territory and peak demand. Compliance with SERC Guideline 3, Criteria for Reliability in System Planning, is established through coordinated studies with the ECAR and SPP interconnected Regions and the SERC subregions. These studies indicate that the Southern Subregion meets SERC Guideline 3. However, studies performed with neighboring Regions and SERC subregions, as well as internal studies by Southern and the Tennessee Valley Authority (TVA), indicate a degradation in the ability to transfer capacity from TVA to Southern. Studies are currently under way to identify system improvements that will increase transfer capability to 1,000 MW by 1992 and 2,500 MW by 1996.

Desired capacity margins for the Southern electric system consider the balance between the cost to the customer of an outage and the cost of additional generating capacity. Capacity margins in this subregion are judged to be adequate during the review period.

Tennessee Valley Authority Subregion

The TVA Subregion is composed of the Tennessee Valley Authority and Tapoco, Inc. It is winter peaking, but is expected to be summer peaking by 1993. TVA supplies the vast majority of the peak demand and is responsible for reliability assessments. The TVA system is regularly analyzed to determine its ability to meet SERC Guideline 3, Criteria for Reliability in System Planning. To accomplish this, TVA participates in reliability studies with adjoining subregions and the ECAR, MAIN, and SPP Regions. Based on these studies, the planned TVA transmission network meets Guideline 3.

TVA's desired capacity margins are determined by the hourly loss-of-load probability method. Planned capacity margins are judged to be adequate during the review period. However, timely completion of planned nuclear generator additions of 4,764 MW will be critical to maintaining adequate capacity margins.

Virginia-Carolinas Subregion

The VACAR Subregion is comprised of eight systems located in North Carolina, South Carolina, and Virginia. The VACAR Planning Task Force is responsible for directing reliability studies within VACAR and for coordination with neighboring NERC Regions and subregions. Studies are accomplished through reliability agreements with ECAR and MAAC and the SERC subregions. Reliability studies performed by VACAR are judged to be adequate for assessment of overall bulk system reliability. Based on these studies, VACAR systems meet the requirements of SERC Guideline 3, Criteria for Reliability in System Planning.

VACAR Subregion capacity margins have declined steadily for many years due to higher than projected demand growth and reduced generation construction. Capacity and load management additions are judged to be at or near minimum levels required to maintain adequate capacity margins throughout the review period.

SERC membership includes 29 systems located in nine states in the southeastern United States. SERC, covering an area of 345,650 square miles, is divided into four diverse subregions that are identified as Florida (the Florida peninsula), Southern (the geographical area of the Southern electric system), TVA (the Tennessee Valley Authority area), and VACAR (the Virginia-Carolinas area). Total population in the Region is about 45 million.

SPP

Southwest Power Pool

The Southwest Power Pool will have adequate generating capacity to supply its projected electricity demands throughout the ten-year assessment period.

The transmission systems will be adequate throughout the period. The simulated 1991 summer peak first contingency incremental import capability of SPP is 3,825 MW. Studies of the transmission systems indicate a reliable network for all simulated first contingency conditions.

SPP, with above normal temperatures during the 1990 summer, experienced a peak demand 6.3% greater than in 1989. The 1991 forecast for the next ten years is for a 1.9% average annual peak demand growth, the same as projected last year. Annual electrical energy growth is projected to average 2.1%, which is up from 2% last year.

Challenges to reliability include the effect of regulations associated with clean air legislation, the deliverability of natural gas, and the impact of increasing demands for transmission services.

Demand and Energy

Since 1985, the Southwest Power Pool (SPP) has experienced five consecutive years of peak demand growth. Because of above normal temperatures during the 1990 summer, the 1990 peak demand increased 6.3% over the 1989 peak and was 1,511 MW greater than forecast. This compares with an average annual increase for the past five years of 3.1%.

The trend for the past five years has resulted in a projection of average annual peak demand growth between 1991 and 2000 of 1.9% to a total of 61,975 MW in 2000. Even with an identical 1.9% average growth forecast for annual summer peak demands made in 1990 and 1991, the 1999 summer peak demand is 411 MW above the 1999 forecast made last year. Actual peak demands and ten-year projections made in 1989, 1990, and 1991 are shown in the figure on the following page. The SPP subregional summer peak demands are projected to increase at rates of 2.3% for Northern, 2.1% for West-Central, and 1.6% for the Southeast.

Annual electrical energy use for the Region is projected to increase at an average rate of 2.1%, which is up from a 2% forecast of last year.

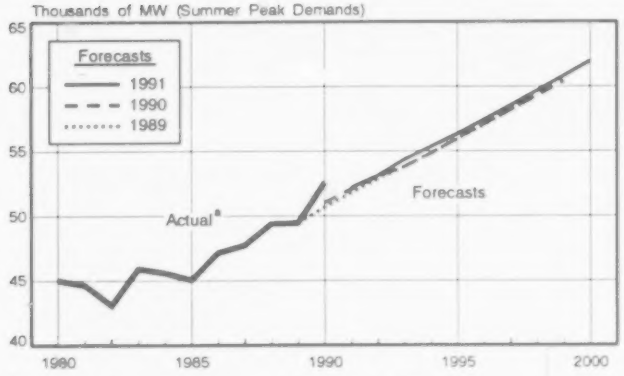
Capacity Resources

Presently, SPP has ample generating capacity to serve its peak demand requirements. Between 1990 and 2000, it is projected that total utility capacity will increase by a net of 6,418 MW to 72,714 MW in the year 2000. This increase includes 1,146 MW of new baseload coal-fired capacity, including one 630 MW unit, over 2,800 MW of uprated and reactivated units, and 2,589 MW of combustion turbine and combined cycle units. During this period, 400 MW of non-utility generating capacity is anticipated to be added to the existing 151 MW of non-utility generators (NUGs).

With the present peak demand and capacity projections, capacity

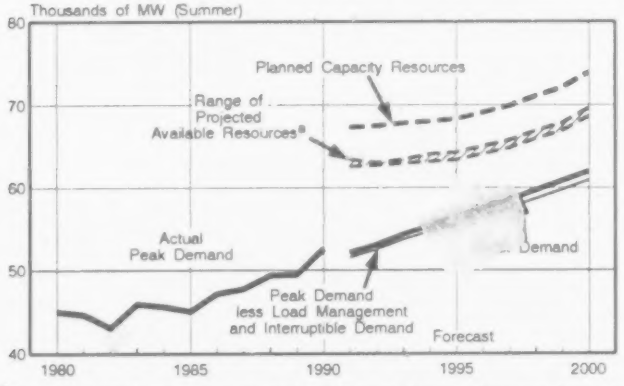
	Year	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Annual Electrial Energy (GWh)	Summer Installed Capability (MW)
Actual	1990	52,541	38,949	252,037	66,833
	1991	52,169	39,567	252,008	67,289
Forecast	2000	61,975	48,082	303,487	73,265
	Growth (%/yr)	1.9	2.2	2.1	0.9

SPP – Recent Forecasts



[a]Not adjusted for weather or operator-controlled demand reductions.

SPP – Supply Adequacy Assessment



[a]Projected Available Resources are equal to Planned Capacity Resources less spinning reserve requirements and projected unavailable capacity at the time of system peak.

margins will meet the SPP criterion of 16.7% throughout this forecast period.

The SPP fuel mix is expected to remain fairly constant over the next ten years with coal accounting for about 56%, gas and oil 27%, and nuclear roughly 14% of total fuel requirements by the year 2000. At the present time, supplies of fossil fuels appear to be adequate. A fairly good balance in the generation mix has helped the Region's reliability adequacy in the past when one of these fuel supplies was curtailed (e.g., the winter cold spell of December 1989 when gas supplies were curtailed).

Transmission Adequacy

No major transmission line was placed in service during 1990. Three utilities in SPP and four utilities in MAPP have agreed to build a 105-mile, 345 kV interregional transmission line. This facility, to be completed in 1992, is located in northwest Missouri and southeast Nebraska. It will provide additional transfer capacity between the two Regions and relieve a first contingency transfer constraint that has existed for some time.

The Region plans two additional transmission facilities of major importance to the reliability of the Region between now and 1995. One is a 157-mile, 345 kV transmission line in western Texas and eastern New Mexico, which will be built by Southwestern Public Service Company for service in 1992. The other planned installation is a new 600 MW HVDC facility (along with 17 miles of 345 kV transmission) located in northeast Texas, west of Welsh generating station. Southwestern Electric Power Company will build these facilities, which will begin operation in 1995.

The above lines are included in the next five-year transmission projection of 171 miles of 230 kV, 279 miles of 345 kV, and 14 miles of 500 kV. Between 1996 and 2000, 146 miles of 230 kV, 196 miles of 345 kV, and 154 miles of 500 kV are planned.

Transfer capability with adjacent Regions of the Eastern Interconnection remain adequate throughout the forecast period. Non-simultaneous first contingency incremental transfer capability imports range from 425 MW to 3,275 MW, and exports range from 750 MW to 3,275 MW with these adjacent Regions. Simultaneous first contingency incremental import capacity for SPP is 3,825 MW in 1991.

Reliability Issues

The SPP members expect to manage the challenges facing the Region to minimize adverse effects on reliability. For example, if the projected peak demand should increase at a rate of 2.5%, and if purchases and demand-side management are only half as effective as planned, then it would appear that SPP will be short of meeting its capacity margin requirements by 1995. However, if accelerated demand growth does materialize, member systems will return a number of mothballed units to service sooner than

planned, and will install combustion turbines and combined cycle units earlier than anticipated.

With 56% of the electrical energy generation in 1991 predicted to be supplied by coal, regulations of the U.S. Clean Air Act Amendments of 1990 become very significant. If the regulations are too severe, a number of existing older coal-fired units may be retired or modified. With significant numbers of gas-fired combustion turbines planned, the ability of fuel suppliers to deliver natural gas with existing pipeline capacity is questionable.

Reliability is a concern with any regulation that involves transmission service. The member systems that own and operate a transmission network must be permitted to operate that network in the most reliable manner with economic generation considerations being determined by the electric utility owners.

Operations

The transmission network is designed to be reliable for all single contingency conditions. There are several isolated, local area limitations that are closely monitored and when required, operating guidelines are implemented to reduce line loadings during contingencies. At times, parallel path (or loop) flow across the SPP Region to the Tennessee Valley Authority and Southern Company interface must be closely monitored and controlled.

The Southwest Power Pool (SPP) includes 44 electric suppliers serving customers in the states of Kansas, Oklahoma, Missouri, Arkansas, Mississippi, Louisiana, Texas, and New Mexico. The membership is comprised of 17 investor-owned utilities, 12 municipal systems, 11 generating and transmission cooperative systems, three state authorities, and a federal agency. SPP currently serves more than 6.6 million customers and covers a geographic area of 500,000 square miles with a population of over 25 million.

WSCC

Western Systems Coordinating Council

The WSCC member systems continue to be optimistic regarding the outlook for reliability within the Region. WSCC's supply of electricity and its transmission network are projected to be adequate to serve the forecast growth in customer electrical requirements during the next ten years. WSCC members recognize that the Region's reliability challenges will include the following issues: fuel supply adequacy, electric and magnetic fields, environmental concerns, special protection systems, and forecast uncertainty. WSCC believes that these concerns can be responsibly managed to avoid degradation of reliability.

Demand and Energy

The 1990 WSCC summer peak demand of 109,787 MW exceeded "normal weather" forecasts by approximately 5.2%. The 1990 through 2000 ten-year annual compound peak demand growth rate for the Region is projected to be 1.5%. WSCC's 1999 demand was projected to be 123,951 MW in the 1990 forecast, and is now projected to be 125,190 MW in the 1991 forecast (approximately 1% higher). Recent actual peak demands and ten-year projections made in 1989, 1990, and 1991 are illustrated on the forecast comparison figure shown on the following page.

WSCC's annual electrical energy requirements are projected to grow at an annual compound rate of 1.8% from 1990 through 2000. This projected growth in annual energy is 0.2 percentage points less than that projected for the 1989-1999 period.

Of the four WSCC reporting Areas, the Arizona-New Mexico Power Area is projecting the highest ten-year (1990-2000) peak demand growth rate (2.1%), while the Northwest Power Pool Area is projecting the lowest growth rate (0.6%). Similarly, the highest ten-year growth in annual energy requirements within the Region is projected in the Arizona-New Mexico Power Area (2.9%), and the Northwest Power Pool Area is projecting the lowest ten-year energy growth rate within the Region (1.6%).

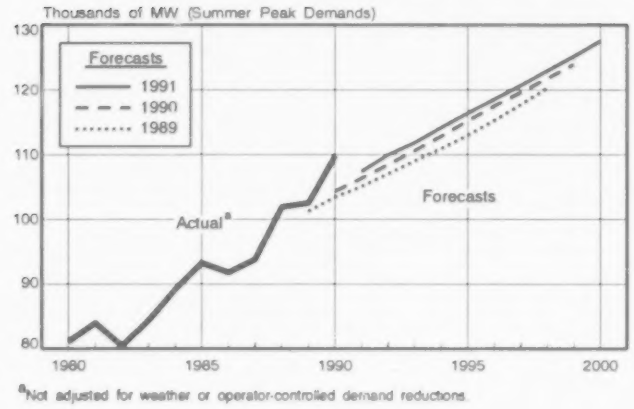
Capacity Resources

Generating capacity that is projected to be available during the next ten years is sufficient to reliably serve the anticipated growth in peak demand and annual energy requirements in all Areas of the Region. The "Supply Adequacy Assessment" figure on the following page indicates that adequate generation margin is planned throughout the forecast period. The range of projected available resources is above the base forecast peak demand (less load management and interruptible demand) throughout the ten-year assessment period. This figure also shows the peak demand uncertainty bandwidth, as described in the "Peak Demand Projections" chapter, for the WSCC Region, which is also known as the Western Interconnection. In the worst case, the WSCC projected available resources do not intersect the upper bound of the forecast peak demand until 1997. The likelihood of needing additional capacity in 1997 is estimated to be no more than 10%.

Net generation additions totalling approximately 14,400 MW are planned through the next ten years. In contrast, net generation additions totalling about 30,800 MW, more than twice the amount currently planned, were placed in service during the last ten years. This difference developed primarily because the growth in electricity demand during the late

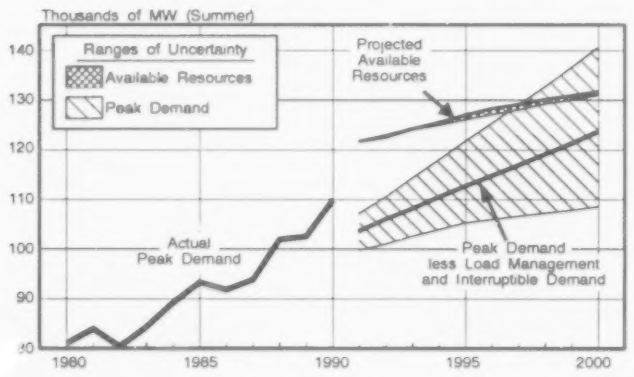
	Year	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Annual Electrical Energy (GWh)	Summer Installed Capability (MW)
Actual	1990	109,787	109,950	650,792	151,184
	1991	107,403	106,760	659,629	147,261
Forecast	2000	127,543	125,708	781,286	159,917
	Growth (%/yr)	1.9	1.8	1.9	0.9

WSCC – Recent Forecasts



[a]Not adjusted for weather or operator-controlled demand reductions.

WSCC – Supply Adequacy Assessment



1970s and early 1980s was well below expectations, creating a generation surplus. The generation plans for the next ten years are consistent with today's lower peak demand and annual energy projections.

Non-utility generators (NUGs) represent 27% (3,887 MW) of the planned ten-year net generating capability additions. Although NUG additions represent a significant percentage of the total planned additions, these resources will account for only 6.8% of the Region's total resources by the end of the year 2000.

Flexibility is a key element in the overall planning process. This process includes consideration of all viable demand and supply options with the goal of maintaining reliability while minimizing the commitment to large capital expenditures and associated financial risks. Conservation and load management programs are examples of viable demand-side management options that are being implemented along with supply options to reliably balance customer demand and generation.

Fuel Supply Adequacy

Increasing reliance upon natural gas as a primary fuel for generating electricity continues to pose a potential reliability risk. Presently, natural gas is an attractive source of fuel due to its clean burning characteristics and current economic advantage. However, gas supply disruptions and significant increases in gas prices could result in future electricity supply problems if too much reliance has been placed on this fuel source.

Transmission Adequacy

The WSCC transmission network, as it exists today and as planned during the next ten years, is adequate to accommodate anticipated firm and most economy electricity transfers. Studies conducted annually by the Council and its members assess the ability of the network to withstand a wide range of single and multiple contingency disturbances. Results of the studies are evaluated relative to the Council's reliability criteria. Potential problems are identified and appropriate action is taken to maintain reliability.

WSCC member systems are making a concerted effort to maintain an acceptable level of existing and future system reliability while accommodating high electricity transfer levels. As an example, operating limits are established on a seasonal basis to define the maximum simultaneous transfers into California that can be accommodated and still achieve reliable performance in the event of a system disturbance. During 100 hours of 1990, electricity transfers into California were curtailed below desired transfer levels to maintain reliability and avoid exceeding simultaneous transfer limits.

Parallel path (or loop) flow has contributed to heavy transmission loadings in a number of locations throughout the WSCC Region for years. To significantly mitigate the Region's major loop flow problems, phase-shifting trans-

formers were installed in the western Colorado-New Mexico transmission system during 1989 and additional phase-shifting transformers were also installed in the transmission lines emanating from Utah to the south during early 1991.

Reliability Issues

Important issues that must be responsibly managed to avoid degradation of system reliability within the WSCC Region include: fuel supply adequacy, electric and magnetic fields, environmental concerns, special protection systems, and forecast uncertainty. These issues are addressed in the discussion of each of the Region's four Areas.

Northwest Power Pool Area

The Northwest Power Pool Area (NWPP) is comprised of the states of Washington, Oregon, Idaho, Utah, portions of Montana, Wyoming, Nevada, and California, and the Canadian provinces of British Columbia and Alberta. Over the period from 1990 through 2000, peak demand and annual energy requirements are projected to grow at respective annual compound rates of 0.6% and 1.6%. Winter generating capacity margins for this winter peaking Area range between 15% and 21% for the next ten years.

Adequate sources of generation are projected to be available to serve the projected demand growth assuming normal weather patterns, average hydro conditions, and the installation of new generation and transmission facilities as planned. However, since most of the Area's electricity is generated from hydroelectric facilities, there is concern regarding generation adequacy should the Area encounter an extended period of below average precipitation or if energy requirements grow at a higher rate than projected. Under adverse hydro conditions, firm energy deficits would be experienced beginning in 1993 and would continue through the end of the ten-year period based upon the current plans for generation additions and demand-side management programs. The deficits would have to be mitigated by the installation of additional generating facilities, expanded demand-side management programs, and electricity purchases.

To facilitate increased resource exchanges and marketing opportunities, utilities within NWPP are pursuing several projects to increase electricity transfer capabilities with other WSCC Areas.

- The California-Oregon Transmission Project (COTP) includes the third 500 kV line from NWPP to California. Together with transmission system reinforcements in Oregon, the COPT will increase the north-to-south transfer capability of the 500 kV lines into California from the existing 3,200 MW rating to 4,800 MW. The full increase in capability to 4,800 MW is expected to be achieved in 1993.

- To significantly increase transmission capability to the California-Southern Nevada Power Area, two 500 kV lines, one from south-central Idaho through eastern Nevada to the Las Vegas area, and one other from central [illegible] the Las Vegas area, are tentatively planned for completion in 1996 and 1997, respectively.

- To increase the electricity transfer capability between Washington and British Columbia, some NWPP utilities are studying a joint plan to increase the transfer capability (2,300 MW on the existing interties) by 700 to 1,000 MW, resulting in a possible 3,000 MW to 3,300 MW total. An alternate plan consisting of a double-circuit 230 kV interconnection north of Spokane is also under study.

Although the outlook for reliability within NWPP over the next ten years is optimistic, there are potential areas of concern.

- Study results indicate a potential for voltage instability in certain areas of NWPP under transmission line outage conditions during winter peak demand periods. The utilities in the Pacific Northwest have implemented operating procedures to address the problem during the near term and have embarked on a major study of the problem to address longer-term solutions.

- Simultaneous transfer capability limits are becoming increasingly important to system reliability. Maximizing simultaneous transfers will result in more complex interconnected system operation demanding the use of more complex operating procedures and increased coordination among utilities.

- A major transmission line siting issue faced by utilities is the concern regarding potential health hazards associated with exposure to electric and magnetic fields (EMF). This issue is a major public concern and is raised in essentially every line siting process. In Washington's Whatcom County, a voter approved initiative has interrupted progress in completing 230 kV transmission lines that are required to maintain reliability of electric supply to the Whatcom

County area. Continued involvement by the electric utilities in scientific studies and public education programs aimed at resolving transmission line siting issues is essential.

- Another significant environmental concern is the effect of river operation on anadromous fish runs. Some of the potentially affected fish may be considered endangered species. Should changes in river operation be instituted, additional electrical energy resources may be required to meet the electricity needs of NWPP customers. This could also increase stress on the transmission network as electrical generation patterns change. Studies are currently under way to determine the impact on transmission facilities and generation needs.

Rocky Mountain Power Area

The Rocky Mountain Power Area consists of Colorado, eastern Wyoming, and a portion of Nebraska and South Dakota. The Area may experience its annual peak demand in either summer or winter. Over the 1990-2000 period, peak demand and annual energy requirements are projected to grow at respective annual compound rates of 1.9% and 2.2%. Summer generating capacity margins range between 15% and 27% for the next ten years.

Generating capacity within the Area is surplus to the Area's near-term peak demand requirements. During the 1991 through 1995 period, about 1,200 MW to 1,450 MW of surplus generating capacity is available for Area demand growth above forecast and for export to other Areas.

Only 3.5% of the Area's firm summer peak demand is projected to be served by NUGs during 1991. However, by the year 2000, the percentage is projected to increase to 10.8%. Due to a number of uncertainties, such as the financial viability of the NUG's primary business and the potential for substantial escalation in fuel costs, the amount of NUGs that will actually be financed and constructed is difficult to predict.

Several additions and changes to the Area's transmission system were placed in service during 1990 to maintain reliability and enhance the ability to export electricity to outside Areas. Transmission additions and reinforcements, planned for operation over the next two to three years, are under way within Colorado to relieve the heavy loadings on the transmission system northeast of Denver.

The outlook for reliability within the Area over the next ten years is favorable. However, the following potential problem areas are sources of concern:

- Continued reliance on special protection systems (remedial action schemes) within the Region for the purpose of operating the transmission network at higher loading levels exposes the electric system to potentially severe consequences if the schemes fail to operate as intended.

- Environmental considerations associated with the EMF issue could adversely affect the construction of new transmission lines, and restrictions on water releases at hydroelectric dam sites could reduce flexibility in the operation of hydroelectric generators.

Arizona-New Mexico Power Area

The Arizona-New Mexico Power Area consists of Arizona, most of New Mexico, and the western-most part of Texas. Over the period from 1990 through 2000, peak demand and annual energy requirements are projected to grow at respective annual compound rates of 2.1% and 2.9%. Generating capacity margins for this summer peaking Area range between 14% and 26% for the next ten years.

This Area experienced significant differences between actual and projected peak demands. These differences are attributed to a combination of abnormal weather patterns in the summer of 1990 and an overall slowdown in local economies. The emergence of non-traditional suppliers is another reason for forecast uncertainty.

During the 1991 through 1995 period, approximately 850 MW to 2,000 MW of generating capacity is available for demand growth above that projected and for export to other Areas. Increased emphasis is being placed on marketing this capacity to utilities in other Areas.

Many of the Area's utilities expect demand-side management to offset a significant portion of their future demand requirements. Concern regarding the amount of demand that can be managed is not as prevalent as in the past, due principally to the development of planning philosophies calling for small, short lead-time, resource additions. Maintenance programs are being used to postpone unit retirements. Slower demand growth rates and demand-side management have reduced the need for new generating capacity in the past several years.

Relatively few NUGs are projected within the Area due to low avoided costs and the generally unfavorable match between the primary industries of the Area and those generally associated with cogeneration.

The Arizona to California transmission system has been strengthened through the years, but continues to be a bottleneck at times. With the addition of phase-shifting transformers across the eastern portion of the WSCC transmission network, the Four Corners transmission system to the west may be somewhat relieved of its historically high loop flow loadings. However, economic pressures to maintain high electricity transfer levels will continue. The Arizona-New Mexico utilities are continuing to work with California and NWPP utilities to make sure that special protection systems (SPSs) operate reliably.

Several transmission projects are planned to increase electricity transfer capability and to improve system reliability. They include:

- A 500 kV line from Phoenix, Arizona to Las Vegas, Nevada. This line, rated at 1,300 MW, is scheduled for service in June 1995.

- A 230 kV line from New Mexico to Arizona. This line, rated at 300 MW, is scheduled for service in 1994.

- A 500 kV interconnection between two neighboring power plants in northern Arizona should increase the transfer capability from Utah/Colorado to Arizona/New Mexico and improve the Area's reliability. The line is scheduled for service in 1994.

California-Southern Nevada Power Area

The California-Southern Nevada Power Area encompasses most of California, southern Nevada, and the northern portion of Baja California, Mexico. Over the period from 1990 through 2000, peak demand and annual energy requirements are projected to grow at respective annual compound rates of 1.4% and 1.8%. Generating capacity margins for this summer peaking Area range between 19% and 23% for the next ten years.

NUGs account for 11.4% of the Area's existing installed generating capacity and 22.2% of the Area's net generating capacity additions over the next ten years. By the year 2000, NUGs are projected to comprise 12.9% of the Area's total generating capacity.

The availability of existing NUGs, especially cogeneration facilities with capacity factors in the 80 to 95% range, has demonstrated that most of these generating units are dependable. In some cases, NUGs have contracted to sell their output to utilities other than the local host utility where they are located. In such cases, issues dealing with transmission service, unit dispatch, and plant control must be resolved among the host utility, the NUG, and the purchasing utility.

Conservation and load management programs will continue to defer the need for new generating plants during the next ten years. Increased commitments to these programs have been made by a number of the utilities in the Area. Southern California Edison Company will defer 1,425 MW of generating capacity due to conservation and load management during this period, and Pacific Gas and Electric Company plans 2,500 MW of conservation and load management.

Air quality regulations are having a significant impact on the feasibility of constructing new generating units. Stringent air quality regulations will hinder development particularly in the Los Angeles basin. For some utilities, repowering (which increases efficiency, decreases emissions, and increases output) is the most feasible and cost effective method to increase generating capacity. The U.S. Clean Air Act Amendments of 1990 require a "New Source Review (NSR)." NSR precludes increased generator unit output by repowering and requires emissions reduction through use of "Best Available Control Technology." Los Angeles basin air quality constraints restrict fossil fuel generation and require increased electrical use for transportation over the next ten years.

The Area's transmission system is being strengthened to maintain reliability and accommodate increased electricity transfers with other Areas. Many of the transmission system enhancements have already been described under the headings of the other WSCC reporting Areas. Additional transmission system enhancements include the following:

- A third 500 kV line extending from the Palo Verde nuclear plant in southwestern Arizona to southern California as early as 1995. This line will significantly strengthen the Arizona to California transmission system.

- An additional 500 kV line from the Las Vegas area to the Los Angeles area in 1995. This line will strengthen the Arizona/Nevada to California transmission system.

Complex operating procedures (nomograms) and special protection systems (remedial action schemes) continue to be widely used as a means of economically managing system reliability. Together, they have made possible increased use of the transmission system by maximizing simultaneous electricity transfers among several Areas. Since overall reliability of the electric system is

critically dependent upon the operating procedures and special protection systems, they must be highly dependable and well coordinated. Their continued use is planned for the future.

Although Area utilities are forecasting an adequate level of reliability over the next ten years, they share the concerns that have been expressed previously regarding those factors that can have an adverse effect upon reliability.

The issues surrounding EMF have resulted in the deferral of several projects within the Area. While these deferrals have not adversely affected the reliability of the WSCC interconnected system, they have reduced reliability at the local level in some cases.

An additional emerging concern within the California-Southern Nevada Area pertains to non-utility transmission. Non-utility transmission is becoming more commonplace in delivering the output of NUGs to their host utilities. To date, all but one of the NUG lines are connected radially from the NUG unit to the network, posing no particular problem from a transmission reliability perspective. However, if the lines are integrated into the network, potential reliability problems can arise if the lines are not designed and operated in compliance with electric system or Regional Reliability Council reliability criteria. Close coordination, joint planning, and operating arrangements are required to assure that all transmission, both utility and non-utility, complies with established reliability criteria and will not cause adverse safety and reliability effects on overall system operation.

Western Systems Coordinating Council (WSCC), with 61 member systems and three affiliates, encompasses approximately 1.8 million square miles of territory in 14 western states, two Canadian provinces, and the northern portion of Baja California, Mexico. The Region is characterized by extremes in population and load densities in addition to long distances between load centers and electric generation sources. The Region is subdivided into four areas, namely: the Northwest Power Pool Area, which is winter peaking and heavily dependent on hydroelectric generation; the Rocky Mountain Power Area, which is either summer or winter peaking with a 25% hydroelectric and 62% coal-fired generating capacity mix; the Arizona-New Mexico Power Area, which is summer peaking with a 19% nuclear and 45% coal-fired generating capacity mix; and the California-Southern Nevada Power Area, which is summer peaking and heavily dependent on gas- and oil-fired generating units.

ASCC

Alaska Systems Coordinating Council

Assessment of the 1991-2000 generation adequacy clearly indicates that sufficient generating capacity margins exist in each of the three major customer demand areas: the Fairbanks area, the Anchorage Bowl, and the Kenai Peninsula. Neither forced outages nor maintenance outages of generator units are expected to adversely impact generating capacity adequacy.

The major reliability issue in the Alaska Railbelt area concerns transmission adequacy. The two existing Railbelt area interconnection lines are single, limited capacity lines prone to outage by weather and avalanche. These lines constrain the sharing of generation among the three customer demand centers and pose a significantly higher than traditional reliability risk for system-wide blackouts due to single contingency outages. If the proposed second interconnection line between the Anchorage Bowl and the Kenai Peninsula, and a second line for a portion of the distance between the Anchorage Bowl and the Fairbanks area (Healy to Fairbanks) are not constructed, the Alaska Railbelt electric utilities will not be able to achieve the level of reliability set forth under NERC guidelines.

ASCC Systems

This assessment addresses only the interconnected electric systems of the Alaska Systems Coordinating Council (ASCC) serving the Anchorage Bowl, the Fairbanks area, and the Kenai Peninsula. These systems are commonly known as the Alaska Railbelt electric utility systems. The Alaska Railbelt electric utilities began interconnected operations in 1984 by interconnecting the Fairbanks area with the Anchorage Bowl. (The Anchorage Bowl had been previously interconnected with the Kenai Peninsula in the 1960s.)

The remaining ASCC utilities around the state also have an ongoing interest in the reliability of their systems. All ASCC utilities (both interconnected and isolated systems) recently adopted the ASCC Planning Criteria for the Reliability of Interconnected Electric Utilities and the ASCC Operating Guides. Therefore, all future interconnections will be addressed under the same criteria.

Demand and Energy

Peak demand for the Alaska Railbelt electric utilities occurs in the winter. The 1990/91 winter peak demand was 613 MW. The projected peak for 1991/92 winter is 625 MW. The winter peak demand forecast indicates an average annual growth rate of 1.6% for the 1991-2000 period.

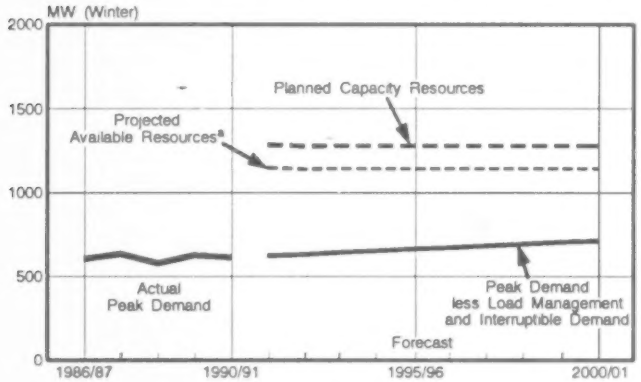
Annual electrical energy requirements to be supplied by the Alaska Railbelt electric utilities are expected to increase at approximately 1.5% over the forecast period. The railbelt economy is influenced by events occurring in the oil industry, and continues to be dependent on changes in oil prices and production levels.

Capacity Resources

Assessment of the 1991-2000 generation adequacy indicates that sufficient capacity margins exist in the three major customer de-

	Year	Summer Peak Demand (MW)	Winter Peak Demand (MW)	Annual Electrical Energy (GWh)	Winter Installed Capability (MW)
Actual	1990	463	613	3,539	1,176
	1991	474	625	3,583	1,284
Forecast	2000	544	718	4,090	1,279
	Growth (%/yr)	1.5	1.6	1.5	0.0

ASCC – Supply Adequacy Assessment



[a]Projected Available Resources are equal to Planned Capacity Resources less spinning reserve requirements and projected unavailable capacity at the time of system peak.

mand areas: Fairbanks, Anchorage, and Kenai. During the assessment period, the Bradley Lake hydro project (108 MW) will come into service and change the capacity mix to 67% natural gas, 17% oil, 12% hydro, and 4% coal.

The Intertie Operating Agreement sets forth the criterion for capacity reserve margin that is used by the interconnected Railbelt utilities. This agreement calls for a 30% reserve margin.

Transmission Adequacy

The major reliability issue in the Alaska Railbelt area concerns transmission adequacy.

The existing 115 kV interconnection between the Kenai Peninsula and the Anchorage Bowl has a poor reliability history and a transmission transfer capacity limit under 75 MW. A second line between Anchorage and the Kenai Peninsula is currently being proposed to improve reliability by preventing the loss of electric service to customers if the existing interconnection line trips (with the exception of those times when the Kenai Peninsula combustion turbines are operating in anticipation of loss of the existing tie).

When Bradley Lake hydro comes into service, reliability will suffer without a second interconnection line between the Kenai Peninsula and the Anchorage Bowl. The proposed second line is necessary to support Bradley Lake and to help reliably distribute the Bradley Lake capacity to the purchasing systems, to minimize blackouts in the Kenai Peninsula, and to minimize underfrequency customer load shedding in the Fairbanks area and the Anchorage Bowl.

Under traditional reliability criteria, a second transmission line between the Anchorage Bowl and the Fairbanks area would likely be required. A second 138 kV line for a portion of this distance is being proposed from Healy to Fairbanks. This additional line would provide a second path between the Healy coal-fired generating plant and the major part of customer demand in the Fairbanks area.

These two proposed transmission lines are subject to funding by the Alaska State Legislature. To date, funding has not been approved. If these lines are not constructed, the Alaska Railbelt utilities will not be able to achieve the level of reliability set forth under NERC guidelines.

Operations

Each Alaska Railbelt electric utility brings into service additional generating units in anticipation of adverse weather conditions. These generating capacity reserves are geographically located such that they would not be restricted by transmission contingencies. This type of operational response enhances reliability and is encouraged.

At the present time, underfrequency customer load shedding studies are being performed. After these studies are complete, appropriate criteria will be developed and implemented so that a coordinated effort can be made within the Railbelt systems.

Reliability Issues

The current balance between economics and reliability is tailored to the unique geographic, electrical, and economic circumstances facing the Railbelt systems. The cost of providing electric system reliability is exceptionally high due to large distances separating the major customer demand centers. In the past, customers have chosen less reliability in favor of economic benefits. However, there are indications that this balance is shifting toward greater reliability, and the Alaska Railbelt electric utilities are faced with some tough decisions in this area.

The Alaska Systems Coordinating Council (ASCC) is composed of eighteen utilities, a state agency, and a federal agency. Nine ASCC members are interconnected in the Railbelt region of the state. These nine ASCC members account for 75% of the utility net generation for the state of Alaska.

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MAIN
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MAPP
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NPCC
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